R.12-03-014/R.10-12-007

Joint LTPP/Storage Workshop:
Meeting Resource Needs with Preferred Resources

Arthur O'Donnell & Nat Skinner

Energy Division
California Public Utilities Commission

September 7, 2012

Remote Access

WebEx Information
Meeting Number: 742 772 641
Meeting Password: storage
Go to
https://van.webex.com/van/j.php?ED=188243962&UID=491292852&PW=NYTMxZTQ4YTcy&RT=MiM0

Call in #:
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Passcode:
3481442

*Note: *6 to mute/unmute*

Upon entry to the call, please place yourself on mute, and remain on mute unless you are asking a question

Agenda

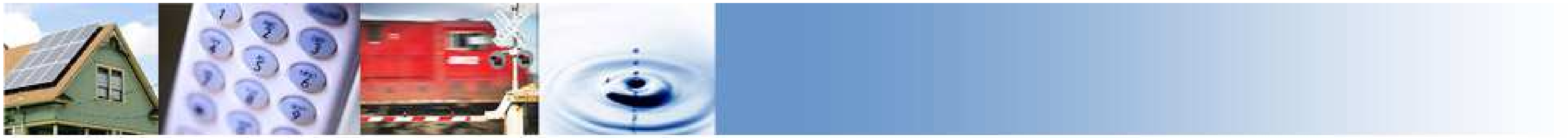
Time	Presenter
9:00 - 9:45 am	Introduction: Energy Division
9:45 – 10:25	Pacific Gas & Electric
10:25 – 10:55	Southern California Edison
10:55 – 11:10	BREAK
11:10 – 11:30	San Diego Gas & Electric
11:30 – 12:00	Vote Solar Initiative
Up to 12:00 pm	Questions?
12:00 – 1:00	LUNCH
1:00 – 1:30	AES Storage
1:30 – 1:50	GenOn
1:50 – 2:10	Calpine Corp.
2:10 – 2:40	TAS Energy
2:40 – 2:55	BREAK
2:55 – 3:25	EnerNoc
3:25 – 3:45	TURN
3:45 – 4:00 pm	Q&A/Next Steps

Workshop Purpose

- This workshop will explore the definition and valuation of energy products and resources that can meet Local Capacity Requirements and System Need, including resources such as storage, demand response, and distributed generation alongside conventional generation.

LTPP Schedule

- Track I (Local Area Reliability)
  – 9/24: Briefs
  – 10/12: Reply Briefs
  – Nov/Dec: Proposed Decision
- Track II (System Reliability)
  – 9/7: Technical comments
  – 10/1: Policy comments
  – November: Proposed Decision
- Track III (Bundled Procurement / Rules)
  – Q3 2012 start expected



Energy Storage Schedule

- Phase 2 -- PHC Sept. 4, 2012
- Scoping Memo
- Workshop on Cost/Benefit, Sept. 24
- Workshop on Use Case Development, October 15-16
- Legislative deadline: October 1, 2013.

Workshop 9:45 – 10:25 am

- Pacific Gas & Electric

Workshop 10:25 – 10:55

- Southern California Edison

Accounting for the Preferred Loading Order in Meeting Incremental Demand for Local Area Requirements

CPUC Workshop

September 7, 2012

Background and Workshop Objective

- CPUC's 2012 LTPP proceeding (R.12-03-014) will assess the need for incremental resources to meet the Local Capacity Requirements (LCR) of SCE's LA Basin and Big Creek/Ventura local areas
- Considerable concern raised by parties that the CAISO's LCR technical studies did not consider "preferred resources" beyond those already committed
- SCE has committed to fully comply with the State's Preferred Loading Order in any LCR procurement it is authorized to conduct
- SCE will elaborate on the options available to account for "preferred resources" in today's workshop

What is the LCR Need for SCE's Service Territory

- CAISO submitted prepared testimony in the 2012 LTPP indicating that the SCE service territory requires:
  - Up to 2,370 MW of existing LCR generation to remain in service in the Western LA Basin or be replaced with similarly located new generation
  - Up to 3,741 MW of new generation in the Western LA Basin if OTC plants retire and new generation is not located near existing generation sites
  - 430 MW of LCR resources to alleviate a transmission voltage concern in the Big Creek/Ventura local area
- CAISO LTPP witnesses identified the technical requirements that must be considered for LCR resources
  - Availability to respond to calls
  - Frequency of calls
  - Number of continuous hours of operation required
  - Response time
  - Certainty of resource response to "dispatch" instructions
  - Voltage Support
  - Ability to provide ancillary services, ramping, and load following
  - Located in the local area

Challenges in Specifying LCR Need

- LCR needs are determined by studying the amount of generation required to relieve contingencies that would impact the reliability of the local area
  - Studied contingencies can change as the grid topology evolves
  - System planners have historically assumed incremental LCR resources will not have operating restrictions
    - Peak demand analysis may not be sufficient if the availability of LCR generation is limited
- LCR resources must collectively “solve” the studied contingencies
  - Multiple resource solutions are possible, making it difficult to adopt a discrete set of LCR operational requirements
  - Effectiveness of a particular resource is dependent upon the balance of the LCR portfolio and identified study contingencies
  - Establishing a common counting or eligibility metric such as the Net Qualifying Capacity (NQC) value used for Resource Adequacy (RA) is not sufficient because LCR resources have to potentially meet multiple requirements

Identification of Preferred Resources

- California's Preferred Loading Order provides for the following priority of resources to meet or reduce electric demand:
  - Energy Efficiency (EE)
  - Demand Response (DR)
  - Renewable Energy
  - Efficient Combined Heat & Power (CHP)
  - Distributed Generation (DG)
  - Clean fossil-fueled generation
- SCE will maximize the use of <u>cost effective</u> preferred resources before relying on clean fossil-fueled generation
- Storage technology has not been specifically identified as a preferred resource, but its operational characteristics warrant consideration as part of "least cost-best fit" procurement solutions
  - SCE is "technology neutral" and supports consideration of all cost-effective options
  - SCE does not support a "set-aside" for a specific technology to meet LCR needs

How Do Preferred Resources Meet an LCR Need?

- Demand reduction programs and technology can <u>reduce</u> the identified LCR need
  - Must be located in the local area to be effective
  - Must be sustained if in the form of EE or "behind the meter" DG
  - Must be available and of a sufficient duration if in the form of DR or "supply side" DG
  - Does not necessarily provide a "MW for MW" reduction in LCR need
- Supply-side resources can <u>satisfy</u> the identified LCR need
  - Locational effectiveness needs to be considered
  - Must be dispatchable or unload dispatchable capacity with a high degree of certainty (e.g., CHP with a largely constant generation output)
  - Have sufficient flexibility to satisfy various CAISO operating requirements
    - Be available for dispatch without timing restrictions
    - Allow for a certain frequency of calls
    - Timely response time
    - Able to provide continuous hours of operation if required

Procurement Approaches to Meet LCR Needs

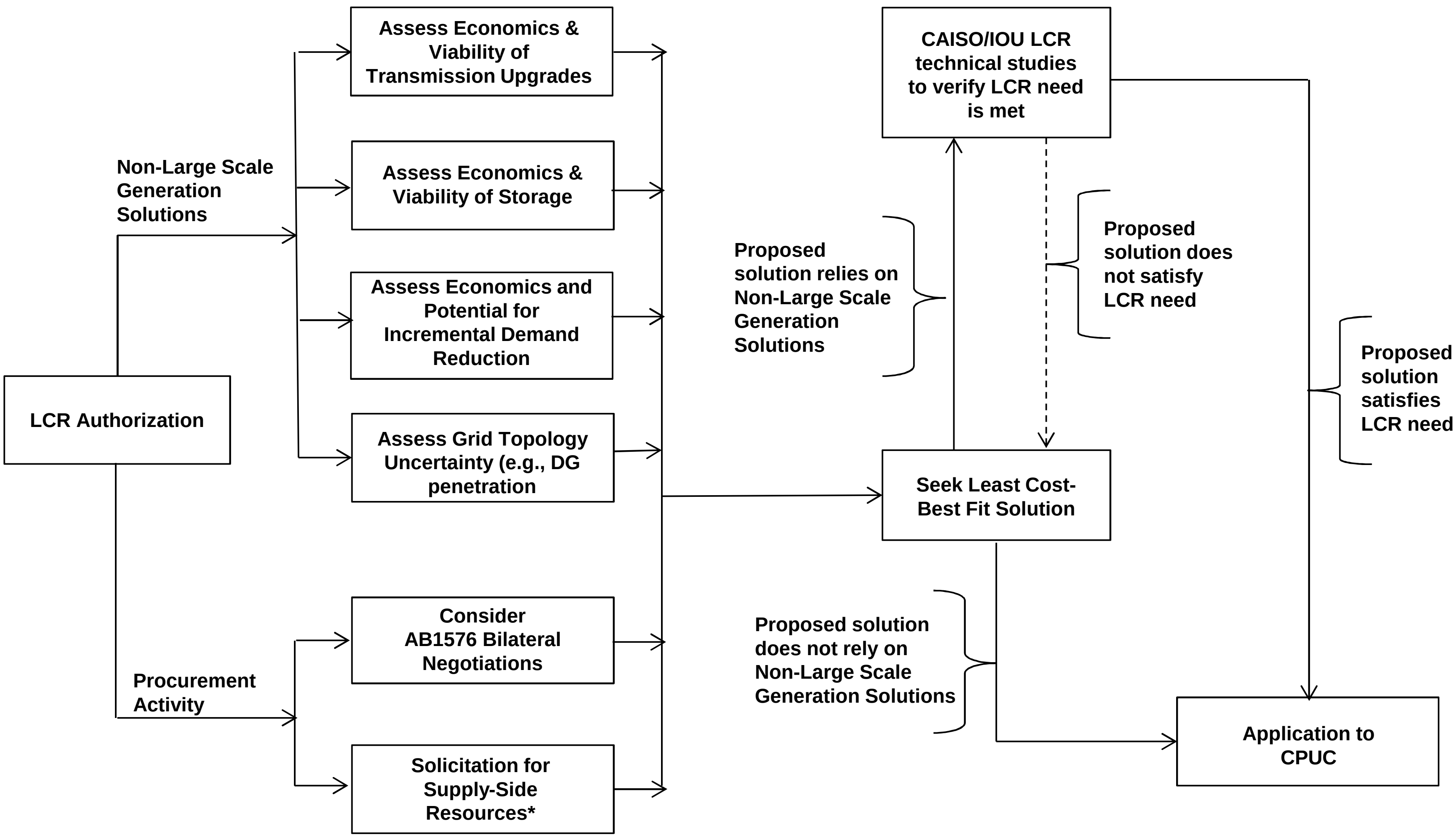
Recommended: IOU Flexibility

- IOU is provided flexibility to simultaneously consider multiple LCR solutions to achieve a least cost-best fit portfolio outcome
  - Solicitations (RFO or RFP)
  - Bilateral Negotiations
  - Cost effectiveness studies for demand reduction resources
  - Deferral of LCR procurement to accommodate future potential LCR solutions or changes in Grid conditions
  - Transmission enhancements
- IOU will file LCR procurement proposal(s) through an application with the CPUC
- IOU must demonstrate compliance with the Preferred Loading Order

RFO with Objective Award Criteria

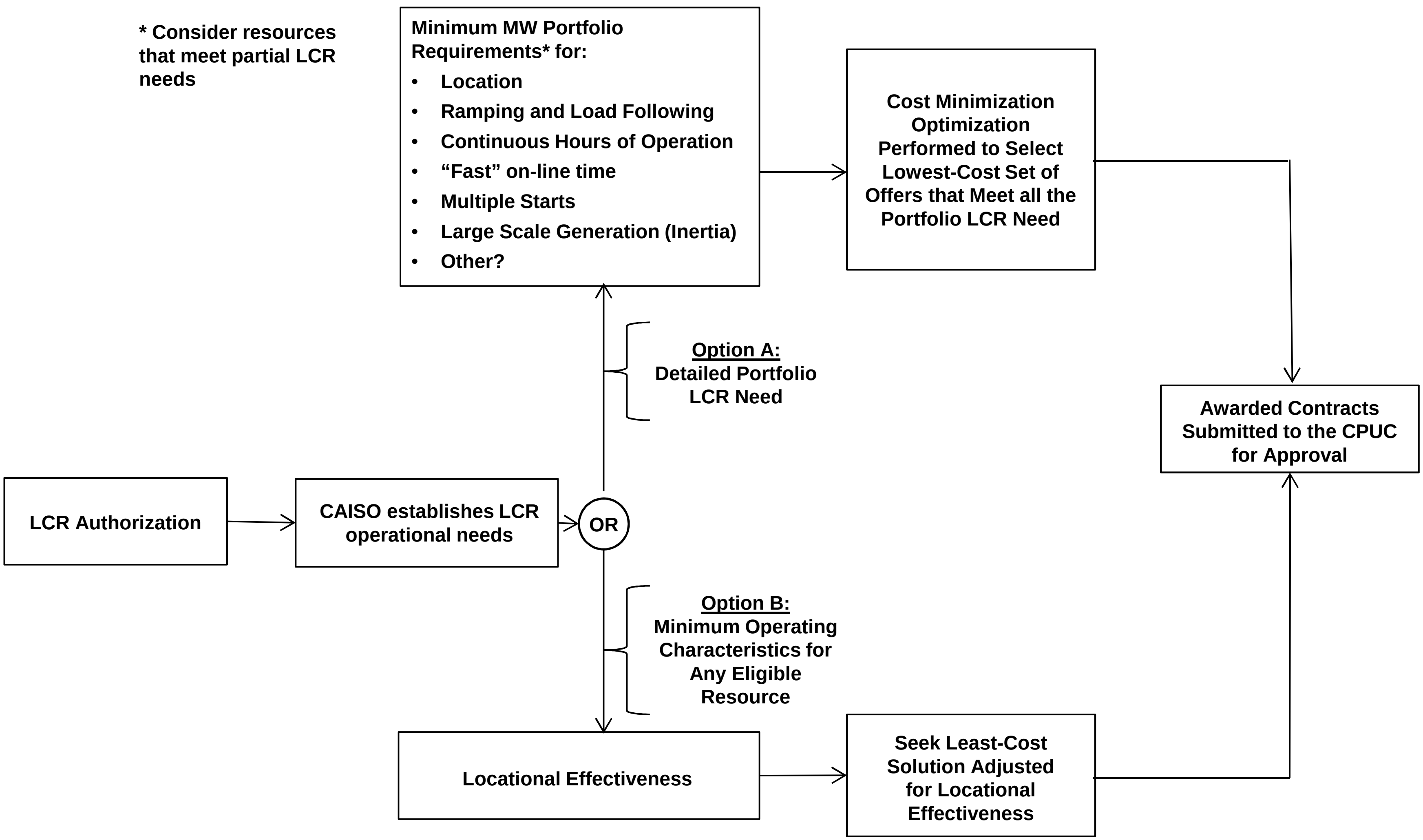
- IOU conducts an RFO to meet the adopted LCR need
- Solicitation is open to all resources that meet eligibility requirements
  - Objective technical requirements are established in conjunction with CAISO
  - Resources must demonstrate commercial and technical viability
- Least cost objective function employed to award contracts
- Awarded contracts submitted to the CPUC for approval

Overview of IOU Flexibility Approach



* Consider resources that meet partial LCR needs

Overview of Open RFO Approach with Objective Selection Criteria



Conclusion

- Providing SCE with flexibility with its procurement activities and assessment of LCR will enhance the ability of preferred resources to be a component of the LCR solution
  - Seeking an LCR “portfolio” solution that considers preferred resources increases the ability of preferred resources to compete
- An RFO process that establishes detailed LCR operating requirements may reduce or eliminate the ability of preferred resources to compete

Workshop 11:10 – 11:30

- San Diego Gas & Electric

SDGE connected
A Sempra Energy utility℠

Thomas Bialek, PhD PE
Chief Engineer – Smart Grid

LTPP and Storage Joint Workshop

September 7, 2012

Response to Workshop Questions

1. What specific characteristics or attributes must a demand-side, storage, or distributed resource provide in order to meet Local Capacity Requirement needs?

- Comply with CAISO tariffs
  - must have full capacity deliverability with the CAISO and a Resource ID
- CAISO currently finishing up its "Deliverability for Distributed Generation" stakeholder initiative
  - CPUC is also expected to discuss this topic in Phase 2 of the current Resource Adequacy proceeding
- Resource is expected to meet the Standard Capacity Product Availability Standards
- Resource must be able to meet the Must Offer Obligations required for that Resource Adequacy resource

Response to Workshop Questions

2. Is energy storage (ES) a “preferred” resource? To the extent it can be shown that ES reduces the emissions profile, should it be considered a “preferred resource” in the procurement

- ES emission reduction depends on the source of its energy
  - Factor in round trip efficiency
- ES solutions need to be cost effective before they can be considered preferred
- Emission impact to be determined by use cases

3. Some parties suggest that ES-based bids and demand-side resources have been disadvantaged during the evaluation process conducted by IOUs for all-source RFOs. What can be done to correct this in future solicitations and evaluations?

- If ES and other demand side resources meet the characteristics defined in (1) above, their ability to meet those characteristics will be valued by the market
- RFOs need to be designed around the characteristics needed by LCR resources

Response to Workshop Questions

4. Currently, energy storage does not have a defined Net Qualifying Capacity value (NQC). How should we measure the NQC for resources such as energy storage or demand-side resources?

- NQC methodologies should be addressed in Resource Adequacy proceeding

5. How can we ensure short-lead time resources are fairly considered in addressing the overall need? What process/infrastructure do we need to ensure that adequate planning and investments occur to enhance the viability of short-lead time resources?

- Commercial attribute, not operational
- Short lead time should be reflected in price

6. In IOU evaluation process, it sometimes happens that resources are rejected because of "non-conforming terms" offered by bidders, including contract lengths that vary from the stated RFO. Is there some need to add more "flexibility" in the contract terms in order to remove barriers to non-fossil flexibility resources? How could we assess the values associated with differing terms of contracts?

- RFO design needs to be around the need, not a specific technology

Response to Workshop Questions

7. In its Opening Testimony in the LTPP proceeding, SDG&E argued that it would be "premature" to include storage as a resource planning purposes or for meeting peak load, as this type of resource would not be developed in time to meet a need identified in this 2012 proceeding, and that available storage technologies are better suited to deal with "intermittency issues" of variable energy resources but not peaking capacity or energy. Are there currently storage technologies that can provide the kind of flexible capacity required to meet needs that might be identified in this LTPP?

- Misstates SDG&E's testimony and implies things that the testimony did not. See SDG&E Track I testimony page 7. The testimony says the following: "With regard to energy storage, inclusion of this resource for resource planning purposes is premature. There exists no reasonable basis to assume that storage will develop in advance of determining local need in this LTPP cycle. Moreover, to the extent energy storage does presently exist, it is intended to deal with intermittency issues. It is not storage that is being specifically designed to contribute to meeting the peak load that local reliability planning must address."

Response to Workshop Questions

- Testimony is about SDG&E's system, and may not apply in all cases across the entire grid
- The "need" should be determined without assuming any storage that does not currently exist
  - Storage can compete with other resources and technology to meet the need
- Does NOT say that "storage is better suited to deal with intermittency."
  - Storage SDG&E has been looking at, as identified in its Smart Grid plan, deals with intermittency and not providing large quantities of firm capacity and energy over an extended peak period
  - Different storage technologies meet different needs and may not meet all needs
- Process should be to identify what is needed to reliably serve customers, independently of how they might be met
  - Storage can then bid to meet those needs
  - The goal should not be how to add storage
  - Holding storage to the same standard as other resources – reliable, feasible and cost effective

Response to Workshop Questions

SDGE connected

A Sempra Energy utility

8. During the LTPP hearings, SCE's witness described two potential ways to conduct a resource procurement, 1) Establishing requirements for resources to meet (i.e., full dispatchability) that might preclude some technologies from effectively competing, or 2) evaluating all potential resources bids for cost-effectiveness, viability, and "best fit" resources. Are there other approaches to a solicitation that might be more inclusive of non-conventional resource types?

- Conducting resource procurement should include both (1) and (2) above. No other approaches necessary

9. Also, SCE and Energy Division have suggested that besides conducting an all-source procurement, it would like to be able to enter bilateral negotiations for "cost-of-service" contracts with certain resource owners. Which method might be more amenable to contracting for non-conventional, flexible resources: an all-source solicitation or bilateral negotiations?

- Solicitation usually best option, but shouldn't rule out bilaterals in special circumstances

Response to Workshop Questions

10. Please consider and provide specific proposals for structuring an RFO for LCR procurement that would allow preferred resources to compete and be considered fairly.

- RFO should be structured with very specific characteristics (see response to question 1 above) listed that will meet the need for which the procurement is intended

Questions?

Thank You

Thomas Bialek

Chief Engineer - Smart Grid

TBialek@semprautilities.com

www.sdge.com/smartgrid/

Workshop 11:30 - Noon

- Vote Solar Initiative

The Role of Distributed Generation in an All Source RFO for Meeting Local Capacity Requirements

Energy Division Workshop on Meeting Resource Needs as Determined in the 2012 LTPP with Preferred Resources

September 7, 2012

THE Vote Solar INITIATIVE

Types of Distributed Generation Addressed in this Proposal

- "BMDG" -- Behind the Meter, Customer Owned (e.g. sized to load commercial or residential rooftop PV)
- "WDG" -- Renewable Wholesale (e.g. RAM or SB 32 projects)
- "CHP" – Combined Heat and Power (e.g. projects subject to the Settlement approved in D.10-12-035)

Vote Solar

WINNING ATTRIBUTES OF BMDG, WDG & CHP

- Preferred Resources in the CA Loading Order
- Locational Flexibility/Mobility
- Faster to Site and Install
- Multi-site Aggregation
- Modular
- Optionality
- Procurement Flexibility
- Zero or lower GHG emissions
- BMDG and WDG is generally renewable

BMDG, WDG & CHP CONCERNS

- Uncertainty regarding whether DG will be built (i.e. the "uncommitted" resource).
- At least at the present time, most DG does not have significant flexible operational characteristics such as dispatchability and ramping.
- For BMDG and small WDG, attempting to fill large MW solicitation requests is impractical.

Vote Solar

SOLUTIONS TO CONSIDER

- Method 1 applies only to BMDG because:
  1) BMDG capital costs are paid for by owner.
  2) BMDG is measured in terms of load reduction.
  3) BMDG requires aggregation.

- Method 2 applies generally to WDG & CHP, but with specific refinements for each.

- Addressing the uncertainty of "uncommitted" resources and the differences in performance between conventional resources and DG is central to both Method 1 and 2.

Vote Solar

Method 1 for BMDG

- Aggregate MW quantities of new BMDG in relevant LRA.
- Offer the MW quantity at a fixed per watt price to be paid in one, immediate lump sum, based on the present value of yearly payments equal to the duration of the installation warranty (similar to the CSI EPBB).
- Offer is multiplied by an "Adjustment Factor" to reflect the load reduction impact.
- If the adjusted Offer is less than or equal to the marginal avoided cost of capacity for CT resources offered in the RFO, the BMDG Offer receives a higher ranking than CT resources.
- Winning BMDG Offer guarantees installation of specified MWs in relevant LRA over a certain period of time, and adjusted MWs of CT capacity displaced by winning BMDG Offers are not procured.

Method 1 BMDG Example
(this is just an example, do not quote me on it!)

Solar Aggregator offers 5 MW of new BMDG in the LA Basin LRA for a one time, up front payment of $2.5mm. This bid is analyzed as follows:

- Quantity = Q = 5000 kW
- Years = Y = 20 years (i.e. 20 year warranty)
- Avoided CT Cost = C = $144/kW-y
- Adjustment Factor = A1 = 50% (as derived from the difference between the CAISO LTPP Track 1 Trajectory and Environmentally Constrained modeling results)

Present Value @ 8% discount of [Q*Y*C*A] = $3.5mm

Solar Aggregator Offer ($2.5mm) <= $3.5mm therefore it is ranked higher than CT resources. CT procurement is reduced by Q*A1, or 2.5MW.

Vote Solar

In addition to all the good things on the earlier "winning attributes" slide, Method 1 is a good approach to including BMDG in an All Source RFO because:

1) It guarantees incremental BMDG will be built in the LRA, removing uncertainty associated with uncommitted resources.

2) No associated debt equivalence or stranded cost risk.

3) Allows for aggregation of very small Preferred Resources in appropriate LRA.

Method 2 for WDG/CHP

- In the relevant LRA:
  1) New WDG offers all in price per kWh.
  2) New or un-contracted CHP offers capacity price.

- If Offer is less than or equal to the Market Price (MP) plus marginal avoided cost of capacity for CT resources offered in the RFO ($CT), as adjusted to account for CT production differences between WDG (A2W) or CHP (A2C), Offer receives higher ranking than CT resources.
  1) For WDG, MP = most recent RAM or SB 32 Re-MAT clearing price.
  2) For CHP, MP = most recent non LCR CHP-only RFO (D.10-12-035)

- Winning WDG or CHP Offer guarantees installation of specified MWs in relevant LRA over a certain period of time, and adjusted MWs of CT capacity displaced by winning WDG/CHP Offers are not procured.

Vote Solar

Method 2 WDG/CHP Example
(this is just an example, do not quote me on it!)

- Solar Project offers $0.10/kWh. MP = $0.09/kWh from last RAM. Offer is $0.01/kWh over MP. If $CT*A2W >= $0.01/kWh, Solar Project Offer is ranked higher than CT resources. CT procurement is reduced by the MW size of the Solar Project Offer as adjusted by A2W.

- CHP offers $120/kW-y. MP = $100/kW-y from last non-LCR, CHP only RFO. Offer is $20/kW-y over MP. If $CT*A2C >= $20/kW-y, CHP Offer is ranked higher than CT resources. CT procurement is reduced by the MW size of the CHP Offer as adjusted by A2C.

Vote Solar

In addition to all the good things on the earlier "winning attributes" slide, Method 2 is a good approach to including WDG and CHP in an All Source RFO because it:

1) Guarantees incremental WDG and CHP will be built in the LRA, removing uncertainty associated with uncommitted resources.

2) Ensures that offers above the established market (i.e. RAM, Re-MAT or CHP RFO) will only be selected if the increment is less than CT capacity that the WDG or CHP is replacing.

3) Utilizes existing Commission programs to help drive WDG and CHP offers to LRA.

Vote Solar

Vote Solar

LAST THOUGHT
(something to keep in mind)

Thoughtful calculation of the Adjustment Factors, referred to herein as:

1) A1 for BMDG
2) A2W for WDG
3) A2C for CHP

is very important to address operational differences between CT and DG performance.

Vote Solar

THANK YOU!

~ and ~

GET SOME SUN.

Workshop 1:15 – 1:25 pm

- GenOn
- No Slides

Workshop 1:25 -1:55

- TAS Energy

TAS Energy Inc.

Generation Storage:
California's Hidden, Flexible, Peak Capacity

Gary Hilberg
Executive Vice President
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economic. clean. energy.

Overview

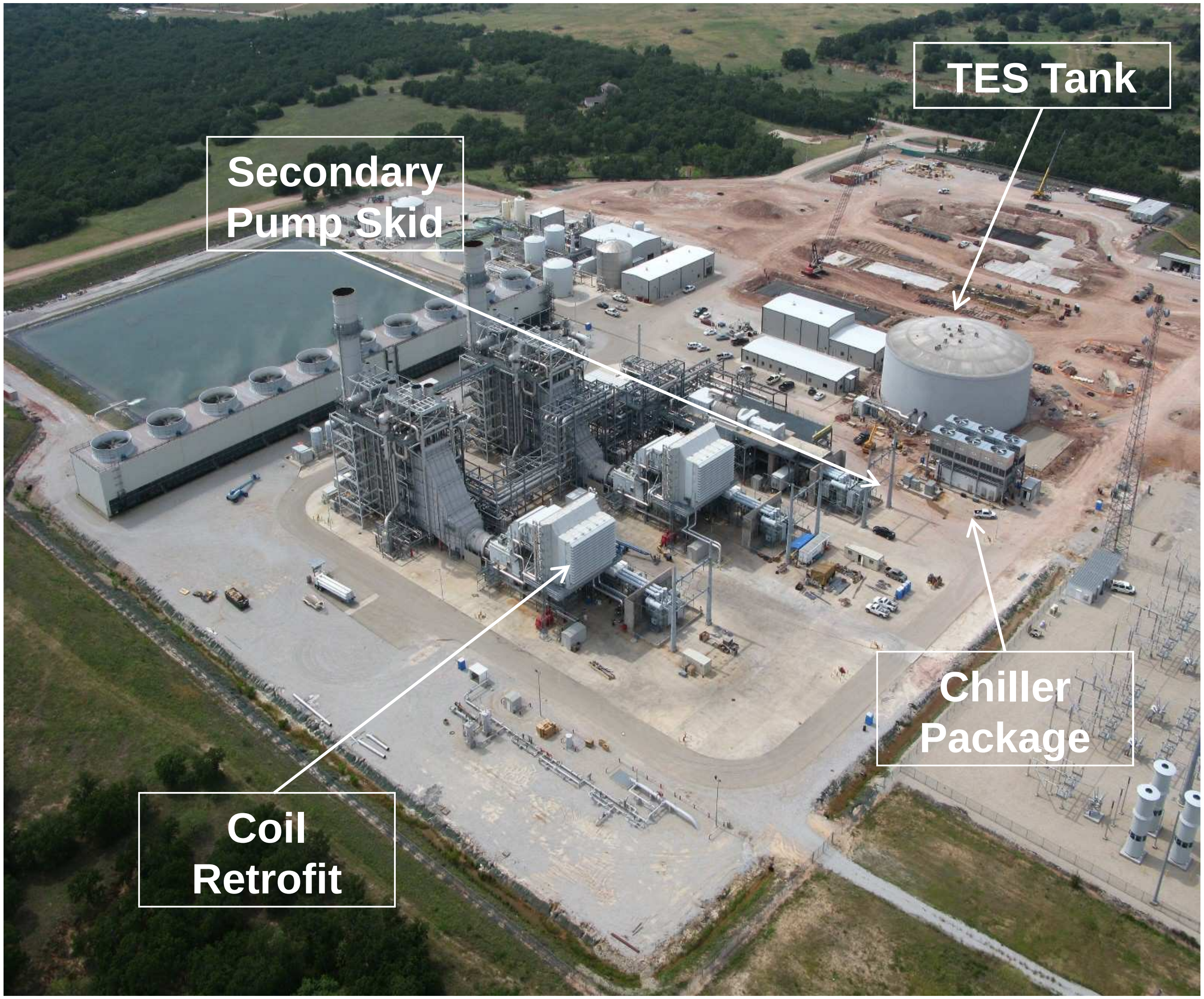
California has ~<u>1,500 MWs hidden within its combined cycle gas fleet</u> that can be tapped for the lowest cost, instant reg up/reg down power; an alternative to new peaking plants

- Total install cost of only $250-$300/kw for green fields and $350-$450/kw for retrofits (compared to $1,000+/kw for a traditional peaker)
- MWs generated at combined cycle efficiency levels
- Proven technology: ~400 turbines around the world have been chilled
- Can be up and running in 9-12 months
- Flexible, dispatchable power in 40-100^{+} MW increments, an alternative to new peaking plants
  - 1/3 the cost, ½ the emissions, no new transmission and no additional maintenance requirements

Technology Review

- ~1,500^{+} MWs of additional flexible capacity available from current combined cycle fleet (higher efficiency than traditional peaking units could provide)
- Total install cost of only $250-$300/kw for new builds and $350-$450/kw for retrofits (compared to ~$1,000/kw for new generation)
- Generation Storage on existing combined cycles offers a first alternative to new generation
  - No new transmission required
  - No additional brownfield sites
  - 9-12 months to operation
  - Flexible MWs offered at combined cycle efficiency
  - Proven technology, hundreds installed around the world
  - 1/3 the cost of a new peaker
  - ½ to 1/3 the CO_2 / regulated emissions of a new peaker

Typical Generation Storage™ Project

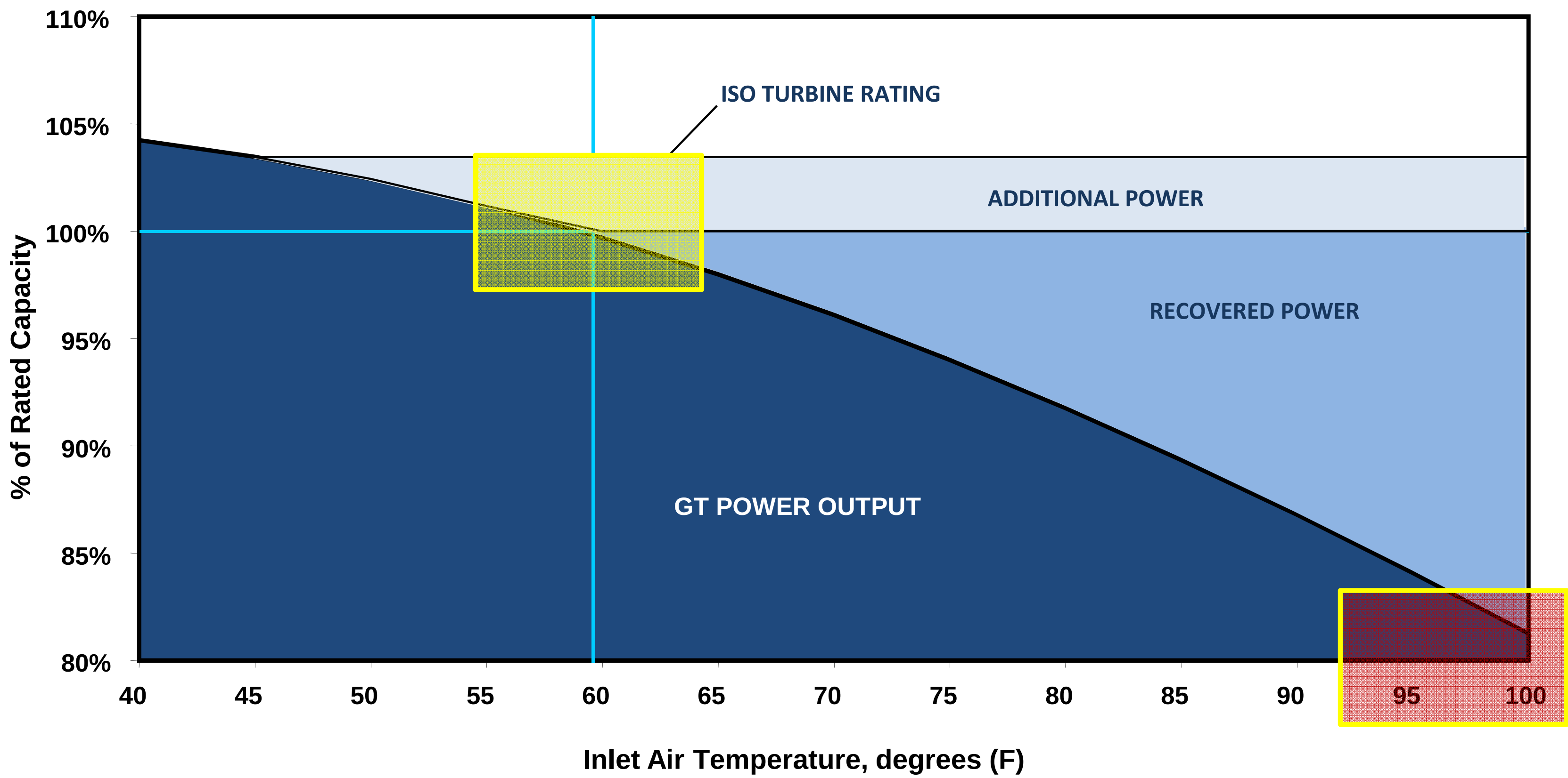


GS Project Profile

- Customer: Electric Cooperative
- Site location: Texas
- Project Timing: 2008-2009
- Outage Duration: ~15-30 Days
- Construction Man-Hours: ~50,000
- Construction Duration: ~9 Months
- Turbine OEM: GE Frame 7FA
- Power Plant Type: 2 x 1 Combined Cycle
- Incremental Plant Output: ~65MW

Weather, GT's & Generation Storage

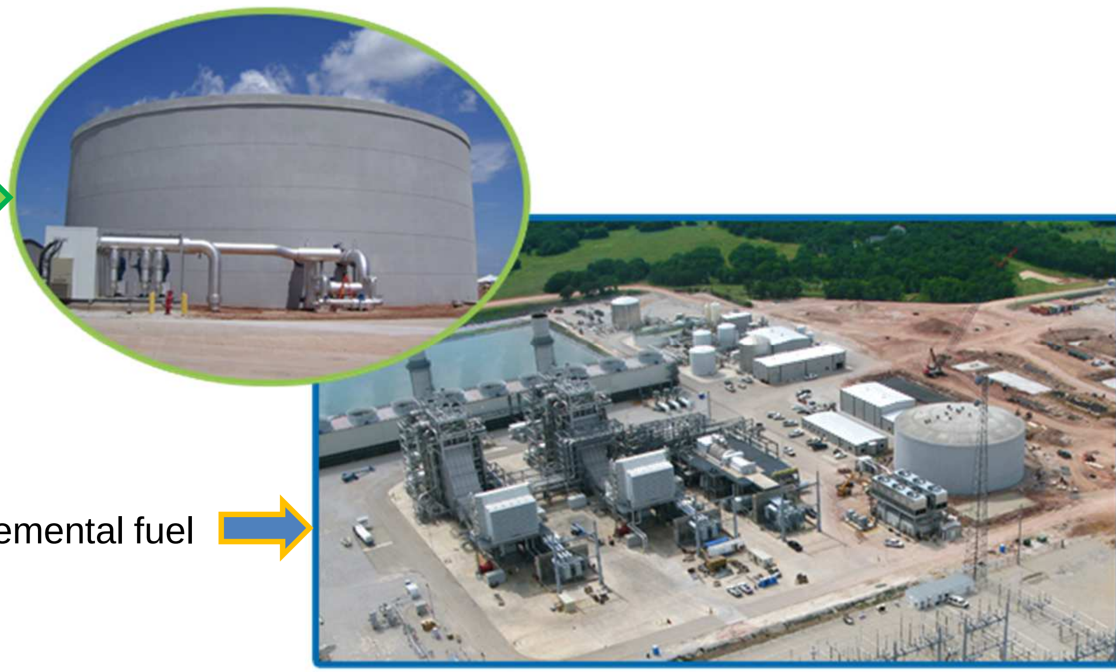
Gas turbines only operate at 100% of their rated capacity when the temperature outside is 59F; the hotter the temperature, the lower the performance.By keeping the weather at a constant low temperature, Generation Storage™ can recover the lost power, and even generate additional power.



Generation Storage™

Generation Storage™ uses power at night (when prices are lower and renewable resources are often available) to chill water that is then stored overnight for use the following day to chill the inlet air of the turbine below the temperature breaking point. This increases the capacity of peak time power by up to 20%, and the storage tank provides almost instantaneous, grid dispatchable, regulation up/down capability (under two minutes) through simple temperature or pump adjustment of water flowing out of the tank.

1 MW-hr
in
Potential in CA:
1,912 MW-hrs
Per night



Incremental fuel

5-8 MW-hrs
out
Potential in CA:
13,464 MW-hrs
Per day

*6-8 to 1 output due to impact of inlet chilling
Storage provides full range of flexible capacity

Sample Case Studies

IPP

PROJECT PROFILE

Combined-Cycle Cogeneration Power Plant

Generation Storage™ Application — Texas, USA

PROJECT FACTS

System Benefit:
Over 51 net MW added
3.5% improvement in heat rate

Ambient Design Conditions:
95°F (35°C) dry bulb
80°F (27°C) wet bulb

Hybrid Refrigeration System:
5 x 60 Hz ABSC-16C Plants, 8,300 TR (29,190 kWth)
1x 60 Hz CVHF-1280 Chiller, 1,200 TR (4,220 kWth)

1x 6.5 mil gals Thermal Energy Storage (TES) Tank

Gas Turbine Information:
3 x W 501D at 105.6 MW each

CHALLENGE

The cogeneration plant operated with three (3) W501D's combustion turbines with a total rated capacity of 316.8 MW before the plant was retrofitted in 1999. More than ever, Independent Power Producers (IPPs) are becoming more aggressive due to their plan to increase their share of the power generation market. This has resulted in IPPs looking for solutions that can make up for the decrease in power output when ambient temperatures increase – allowing them to sell more electric energy when demand increases.

SOLUTION

Management decided to evaluate various solutions for increasing plant capacity for the sale of electric energy during on-peak periods. These various solutions included evaporative cooling, fogging, electric chillers, absorption chillers and hybrid systems. When comparing solutions, the Turbine Inlet Chilling (TIC) systems with chillers achieved a greater increase in power capacity because chillers can reduce the inlet temperature to 50°F (10°C) while evaporative cooling and fogging can only reduce inlet air temperature to 81.5°F (27.5°C), respectively. In addition, the parasitic power need of a direct-fired, double-effect absorption chiller is the lowest while that for an electric chiller is the highest.

With the evaluation of various solutions, TAS Energy's Generation Storage™ was utilized for the retrofit that included installation of a hybrid refrigeration system including a combination of absorption chillers, an electric chiller and a Thermal Energy Storage (TES) tank, custom built filter houses with cooling coils and a heat recovery coil retrofit.

IOU

PROJECT PROFILE

1,100 MW POWER STATION

Generation Storage™ Application — Pennsylvania, USA

PROJECT FACTS

System Benefits:
TIC contribution of additional 118 MW
10+% net output compared to base, ISO
Neutralized heat rate

Ambient Design Conditions:
95°F (35°C) Dry Bulb
75°F (24°C) Wet Bulb

Hybrid Refrigeration System:
Two (2) TAS F50, 11,000 TR (38,685 kWth), Multi-stage Centrifugal
Dedicated Cooling Towers
1 x 7.6 mil gals Thermal Energy Storage (TES) Tank

Gas Turbine Information:
(2) 2 x GE 207FA each

CHALLENGE

The power station was experiencing only 87% of the rated output at 95°F (35°C). This output was decreasing significantly as temperatures rose. Unfortunately, this also occurred when demand was at its highest. This problem was not being addressed by the existing fogging system so the power station owner searched for a solution that would improve output for added summer capacity and create heat rate flexibility.

SOLUTION

Various augmentation solutions were reviewed, including some offered by the gas turbine OEM. After reviewing the short- and long-term system benefits, TAS Energy's Generation Storage™ solution, the combination of TAS Energy's patented Turbine Inlet Chilling (TIC) system and a Thermal Energy Storage (TES) tank, was chosen.

With TAS Energy's TIC solution, the power station was able to produce inlet air temperature of 50°F (10°C). This enabled the gas turbine to generate above its ISO rating. TAS Energy also designed and engineered the solution of a TES tank to provide the ability to pull electricity from the grid at night-time hours (and pricing) to chill the water and have it stored for use the following day during peak demand.

COOP

PROJECT PROFILE

TEXAS COOPERATIVE

Generation Storage™ Application — Texas, USA

PROJECT FACTS

System Benefit:
90 net MW added
Improvement in heat rate

Ambient Design Conditions:
95°F (35°C) dry bulb
75°F (24°C) wet bulb

Generation Storage™ System:
2x 60 Hz Chiller, 7,800 TR (27,431 kWth) 1x 6.1 mil gals Thermal Energy Storage (TES) Tank

Gas Turbine Information:
4x GE Frame 7FA

CHALLENGE

The plant is rarely offline as it supplies power to multiple member co-ops and municipal system(s) as well as sells into the spot market. It is critical for plant operations to maximize generation and efficiency. When the plant began design of a second 7FA-powered 2x1 for the site, options including turbine inlet chilling (TIC) to maximize the plant's output were considered.

SOLUTION

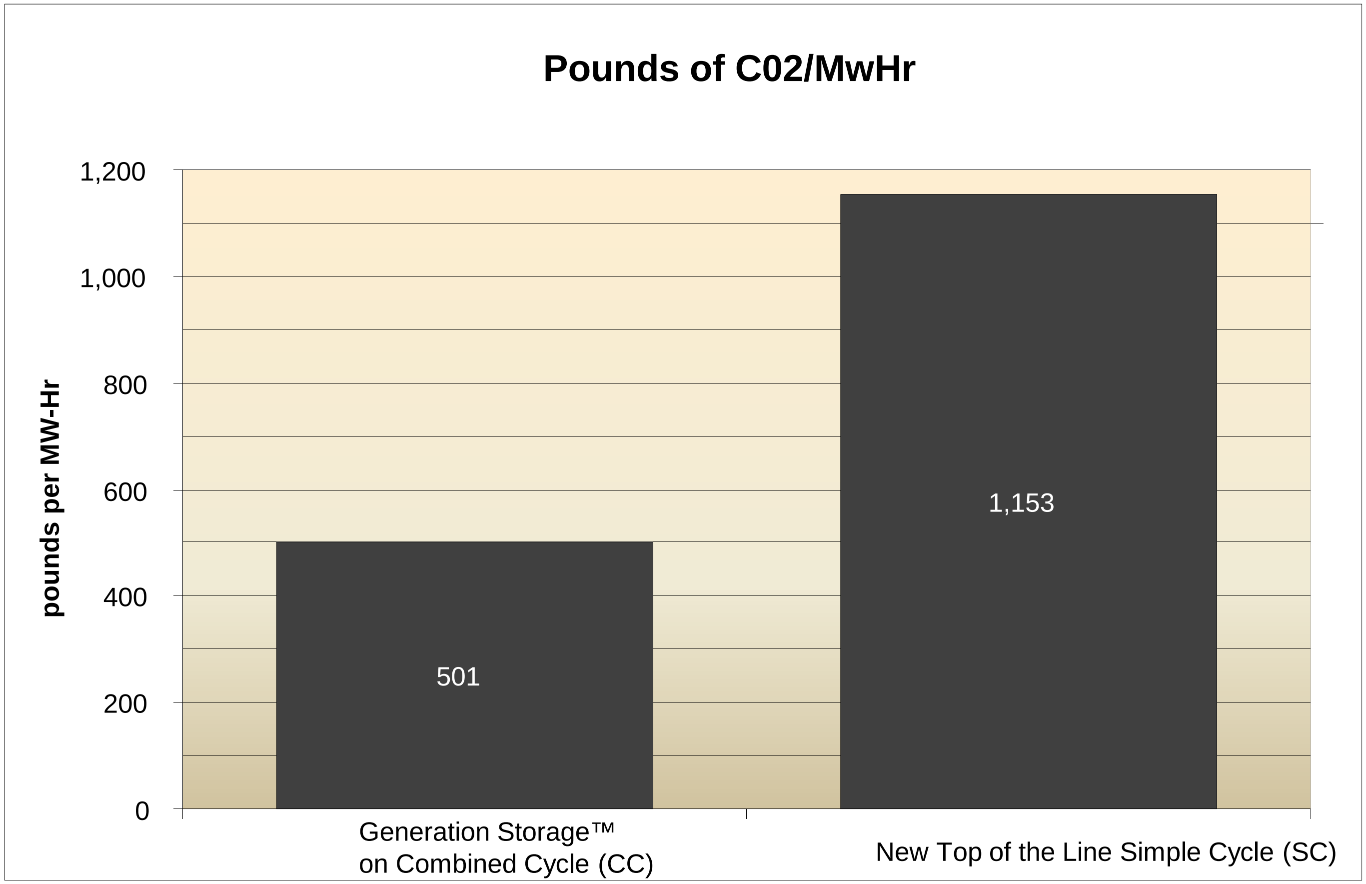
Various solutions were discussed and studies concluded that on a hot summer day, evaporator coolers could only produce 560 MW whereas with TAS Energy's TIC packaged solution, over 600 MW could potentially be produced. It was decided that it was economical and beneficial to retrofit one unit and incorporate TIC to the new unit as well. In addition, a 6.1-million-gal Thermal Energy Storage (TES) tank was integrated with the unit's TIC system to result in TAS Energy's Generation Storage™ packaged solution. The TES tank supplies chilled water for both combined cycle Units 1& 2 and allows the plant operator to pull electricity from the grid at night-time hours (and pricing) to chill the water and have it stored for use the following day during the peak demand.

A Preferred Resource

Attributes to Be Valued: A "Win" For Everyone

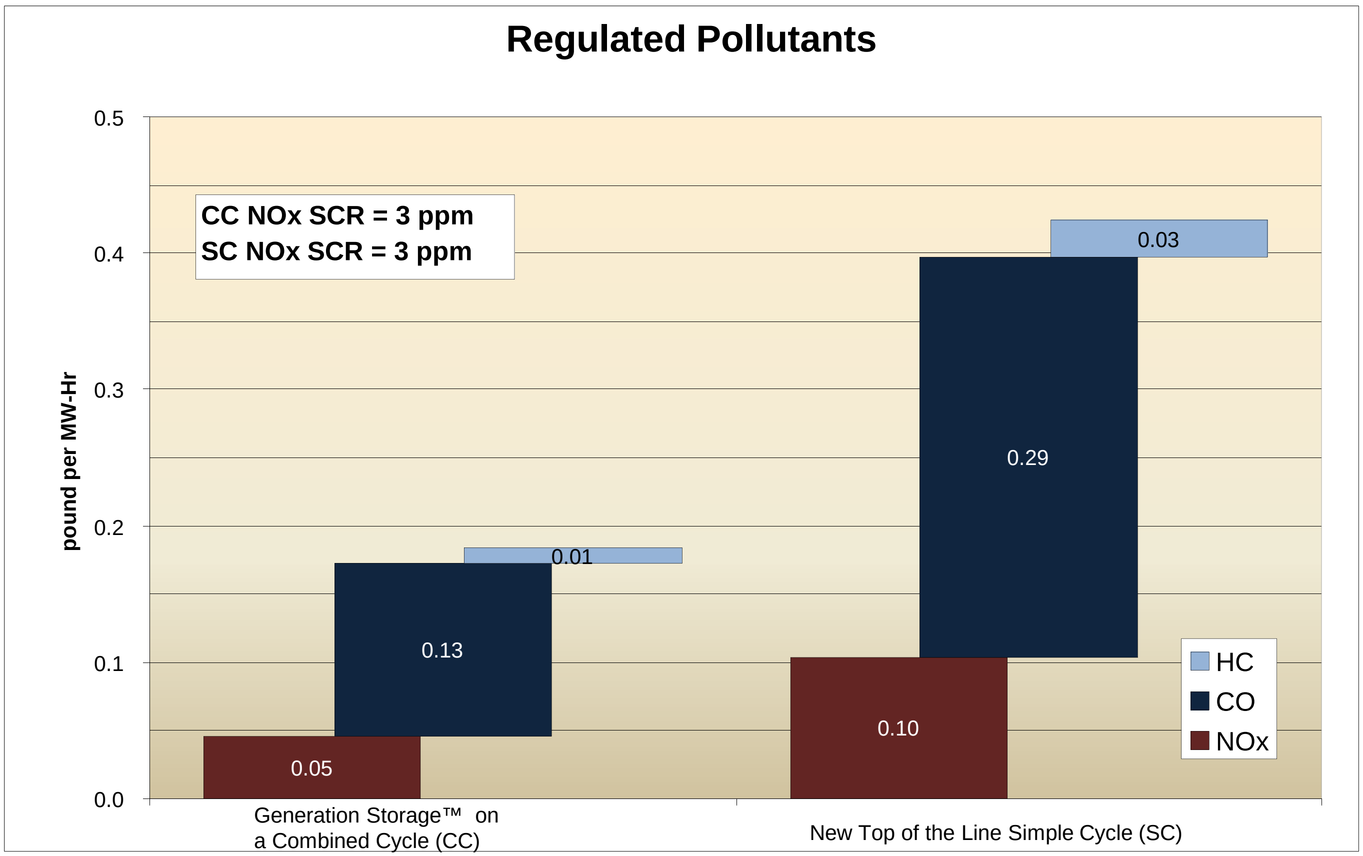
- Not just capacity, but *FLEXIBLE* capacity
- Speed to Market (under one year)
- No New Transmission Required
- Planning Flexibility: Incremental Power Addition
  - Allows utility to purchase power in increments, retrofitting assets in regions that need the power rather than adding hundreds of megawatts that might not be needed
- Enhancement to Existing Assets Already Financed by Rate-Payers
- Significantly lower environmental footprint than new simple cycle facilities

Environment Impact



* Graph effectively shows the difference between CC and SC performance. When Generation Storage™ is added to a CC, it provides the same power as a SC, but at CC emissions levels

Environment Impact



* Graph effectively shows the difference between CC and SC performance. When Generation Storage™ is added to a CC provides the same power as a SC, but at CC emissions levels

RFO Barriers to Market

- **A separate contract needs to be available for IPPs to receive financing for the new flexible capacity that would be generated through the addition of Generation Storage. This contract should be able to occur in parallel with the facility's existing contract**
  - Under status quo there is a perceived if not real risk that incremental megawatts gained through GS would not be compensated for, without renegotiating the original contract (a non-starter for IPPs).

- Most RFO's are written specifically encouraging bids for 'new steel in the ground.' A clear statement that storage, retrofits to existing assets, and other technologies are invited to bid is necessary

RFO Barriers to Market

- RFO's should seek to identify and value all attributes of technologies that bid, not just cost (although cost should be a primary consideration) including: flexible capacity, planning flexibility, speed to market, transmission needs, environmental footprint, etc.

- Storage and other technologies with preferred attributes capable of providing the same peaking power should be evaluated as an alternative to all new peaking projects before the CEC

Regulatory Review

- Cost effective storage technologies exist today, and have been deployed in other states, capable of providing peaking power and renewable integration services
- Changes to current RFOs need to be made to ensure storage, retrofits to existing assets, and other technologies are able to bid into today's RFOs
- Storage, and retrofits to existing assets should be considered 'preferred' due to environmental impact, flexibility in capacity and planning, transmission needs, etc.
- The Commission should consider multi-year resource adequacy contracts to complement LTPP offerings

Other Considerations

- Currently the mechanism for financing a capital intensive project is the LTPP 10 years out process (as traditional resources often require a long lead time for completion)
- We would suggest the Commission consider offering multi-year (5 years or greater) Resource Adequacy contracts to compliment LTPP efforts that would allow for needed incremental flexible generation to be financed
- A second suggestion would be to consider allowing IOUs to offer LTPP contracts with an “option” to build and come online before 2022 (if need is determined) from technologies capable of being deployed more quickly, like Generation Storage

Workshop 1:55 – 2:25 pm

- AES Storage

Energy Storage: A Long-Term Flexible Capacity Resource

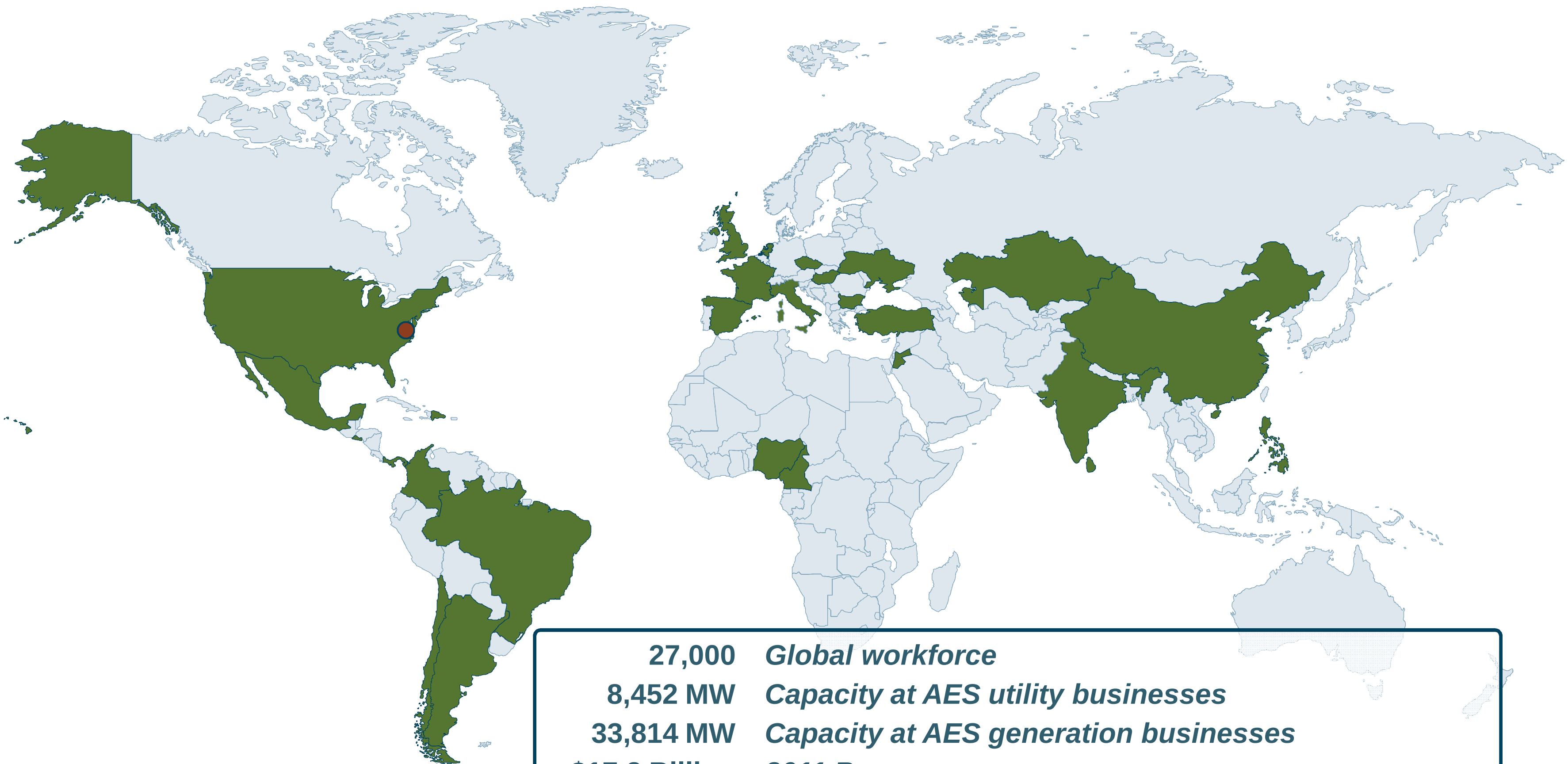
September 2012

CPUC Joint Workshop of LTPP & Energy Storage – San Francisco

AES
Energy Storage

AES operates power facilities in 27 countries.

Our mission is to improve lives by providing safe, reliable and sustainable energy solutions in every market we serve.



27,000	***Global workforce***
8,452 MW	***Capacity at AES utility businesses***
33,814 MW	***Capacity at AES generation businesses***
$17.2 Billion	***2011 Revenue***

Key ● AES Headquarters ■ AES Operations

AES has been serving utilities with reliability services for 30 years.

AES Energy Storage

AES Products	AES Utility Customers (U.S.)

Energy

Clean Energy

Capacity (R. A.)

Regulation

Voltage Support

Spinning Reserve

Transmission

Distribution

PG&E

Xcel Energy

delmarva power

FirstEnergy

OG&E

Southern California Edison
An EDISON INTERNATIONAL Company

ODEC
Old Dominion Electric Cooperative

Bonneville Power Administration BPA

Direct Energy.

Hawaiian Electric Company

Alliant Energy

AEE
Autoridad de Energía Eléctrica

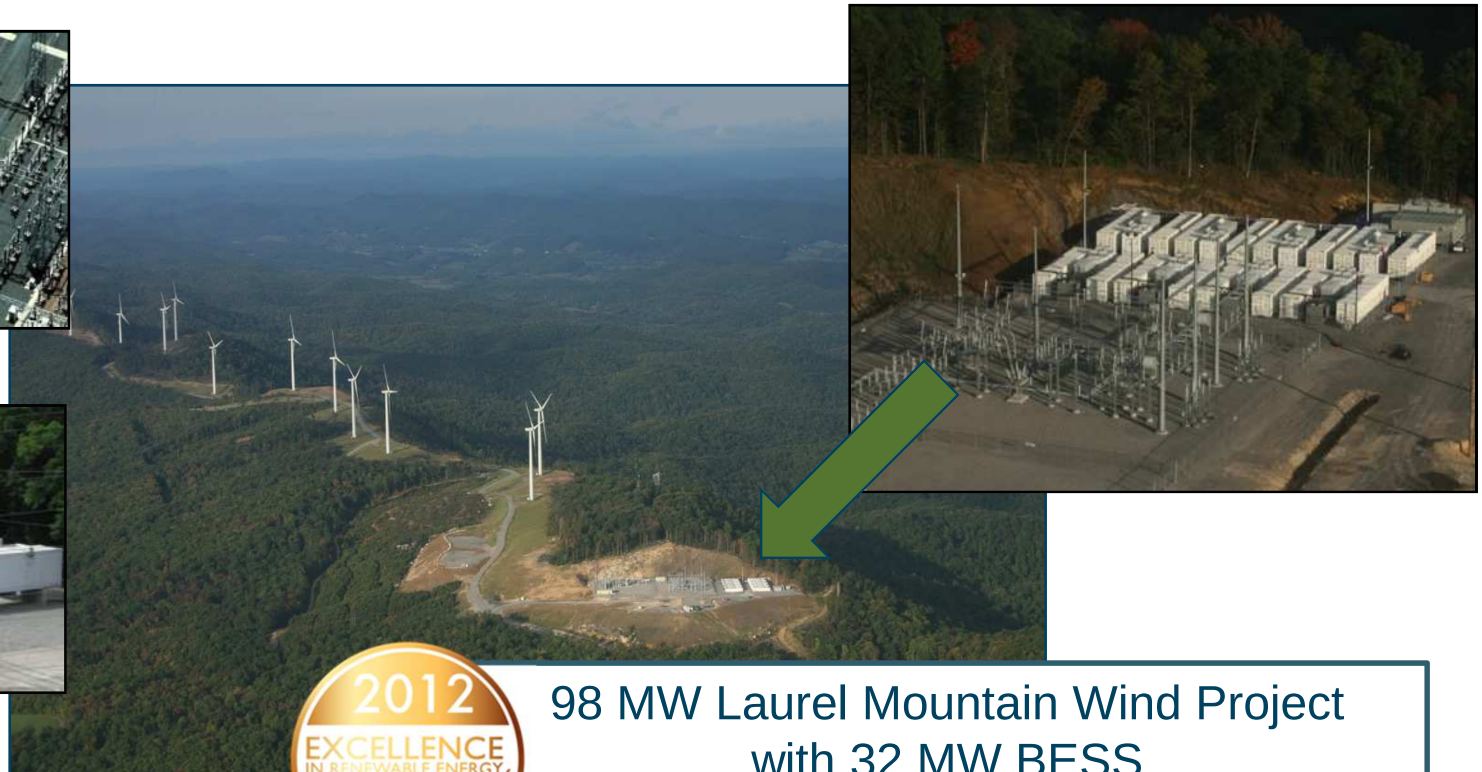
Commercial, battery-based energy storage is available today.

AES Energy Storage

Chile

New York

Chile



2012 EXCELLENCE IN RENEWABLE ENERGY awards WINNER

98 MW Laurel Mountain Wind Project
with 32 MW BESS
Serving PJM Market

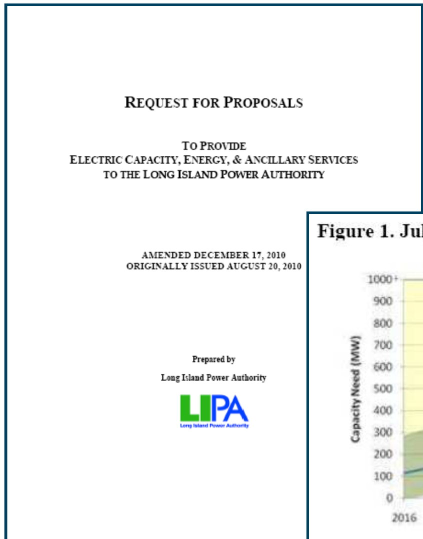
Member:

ESA ELECTRICITY STORAGE ASSOCIATION

NY BEST New York Battery and Energy Storage Technology Consortium

TESA Texas Energy Storage Alliance

AES Energy Storage's product is a long-term commitment to provide flexible peaking capacity.



REQUEST FOR PROPOSALS

TO PROVIDE
ELECTRIC CAPACITY, ENERGY, & ANCILLARY SERVICES
TO THE LONG ISLAND POWER AUTHORITY

AMENDED DECEMBER 17, 2010
ORIGINALLY ISSUED AUGUST 20, 2010

Prepared by
Long Island Power Authority

LIPA

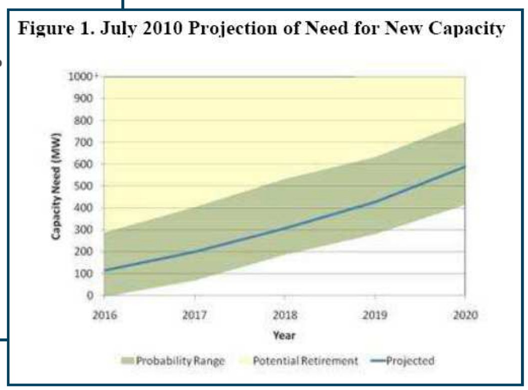


Figure 1. July 2010 Projection of Need for New Capacity

Long Island BusinessNEWS

SEPT. 23-29, 2011 | VOL. 58 | NO. 42 | $2.00 | libn.com

LIPA eyes world's biggest battery

400-megawatt proposal would store energy for peak usage

By CLAUDE SOLNIK

As it reviews proposals for up to 2,500 megawatts of electricity, including wind,

Energy storage facility in Johnson City, N.Y.

"I think utility grid storage makes sense. It's part of the equation we have to look at," said Robert Catell, former KeySpan chairman and now chairman of the Advanced Energy Research and

erator needs to ramp up. "If we need to produce power, we can produce power nearly instantaneously," Perusse said.

Although lithium ion batteries are the most likely candidates, Kathpal said various innovations could allow large-scale projects.

Perusse said the latest generation of batteries is safer, more durable and more efficient than in the past, able to return about 90 percent of the power that's stored.

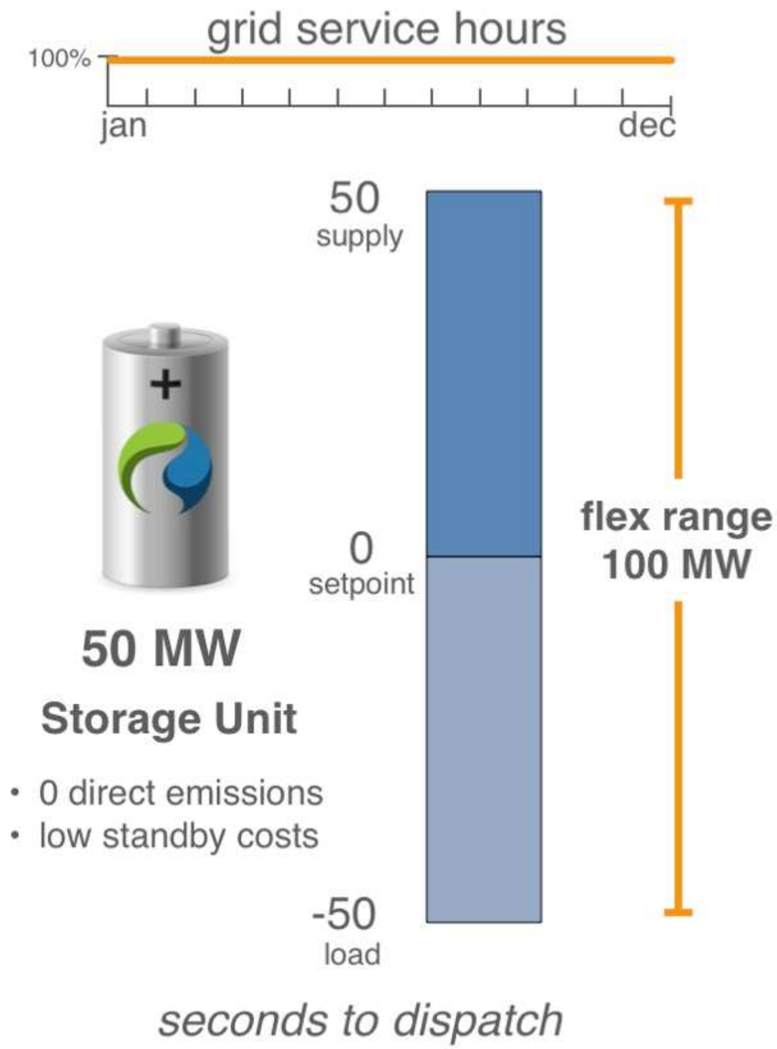
"There's a variety of technologies," Kathpal said. "Massive improvements have been made in battery technology in recent years."

While AES didn't say how much the project would cost, Kathpal said the company believes "our overall value and net

- Responsive to needs stated in utility RFP/RFO.
- Complementary to existing portfolio and other offered options
  - Increased utilization of combined cycle generation -- the cleanest, most efficient, lowest emissions new conventional resources in CA.
- 20+ year tolling agreement.
- Least cost source of flexible capacity.

Our product creates measurable value by meeting our customers' stated needs.

- ☑ Local capacity
- ☑ Tolling agreement
- ☑ High availability
- ☑ Operational flexibility
  - ☑ Many fast starts and stops
  - ☑ Low turn down
  - ☑ Fast ramp rates
  - ☑ AGC
- ☑ Planning flexibility
  - ☑ Siting
  - ☑ Delivery term
  - ☑ Contract length
- ☑ No direct emissions
- ☑ Energy efficiency



RFO evaluation can be improved to enable the participation of energy storage and other resources.

- Portfolio evaluation of market and non-market benefits
- Valuation of operational flexibility
  - Wider operating range
  - High number of service hours – always synchronized
  - Regulation performance vs projected needs
- Impact on dispatch of existing and offered resources
  - Utilization
  - Starts
  - Emissions
  - Minimum generation / out of merit
- Risk mitigation
  - Modular – high availability, reduced LOLP
  - Flexible delivery term – option to shift CODs
  - Dampen impact of fuel price volatility

Workshop 2:15 – 2:30

- Calpine

CALPINE®
NYSE CPN

A GENERATION AHEAD, today

Long-term procurement of flexible capacity

Matt Barmack
Director, Market & Regulatory Analysis

September 7, 2012

CLEAN MODERN EFFICIENT FLEXIBLE POWER GENERATION

How can existing capacity be modified?

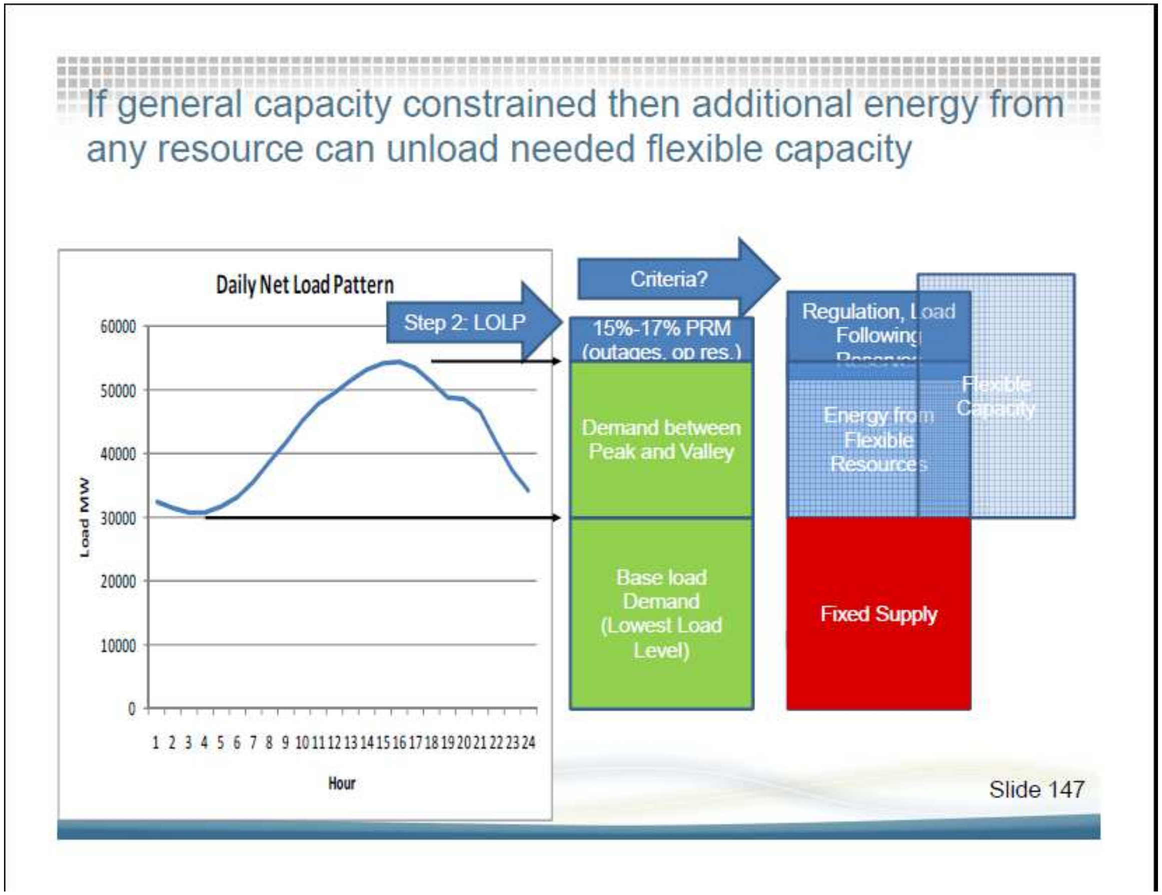
		CPN CCGT (today)	CPN CCGT (upgrade)	New generation CCGT
Capacity	[1]	550	600	625
Fullload heat rate	[2]	7.0	6.85	6.6
Warm start	[3]	90	30-60	30
Cold start	[4]	240	90	30
Ramp rate	[5]	10-12	20-25	30

Notes:

[1] MW (2x1)
[2] MMBtu/MW HHV (2x1)
[3] Minutes to achieve Pmin (1x1)
[4] Minutes to achieve Pmin (1x1)
[5] MW/minute per engine between Pmin and Pmax

Is operational flexibility needed?

- Do we need more MW, more flexibility, or both?
  – Adding inflexible MW potentially unloads flexible MW to provide flexibility-related reserves



If operational flexibility is needed, how is it valued?

- Unclear that CAISO flexibility metrics capture important elements of flexibility
  - Lowering start times may not increase maximum continuous ramping or load following capability

    - For example, the CAISO proposed formula to calculate the "maximum continuous ramping" capacity of a resource is

    min(Pmin + (longest ramp duration-SUT)*RRavg, NQC)

    - For reasonably long durations, the "maximum continuous ramping capacity" of most CCGTs would be equal to their NQCs

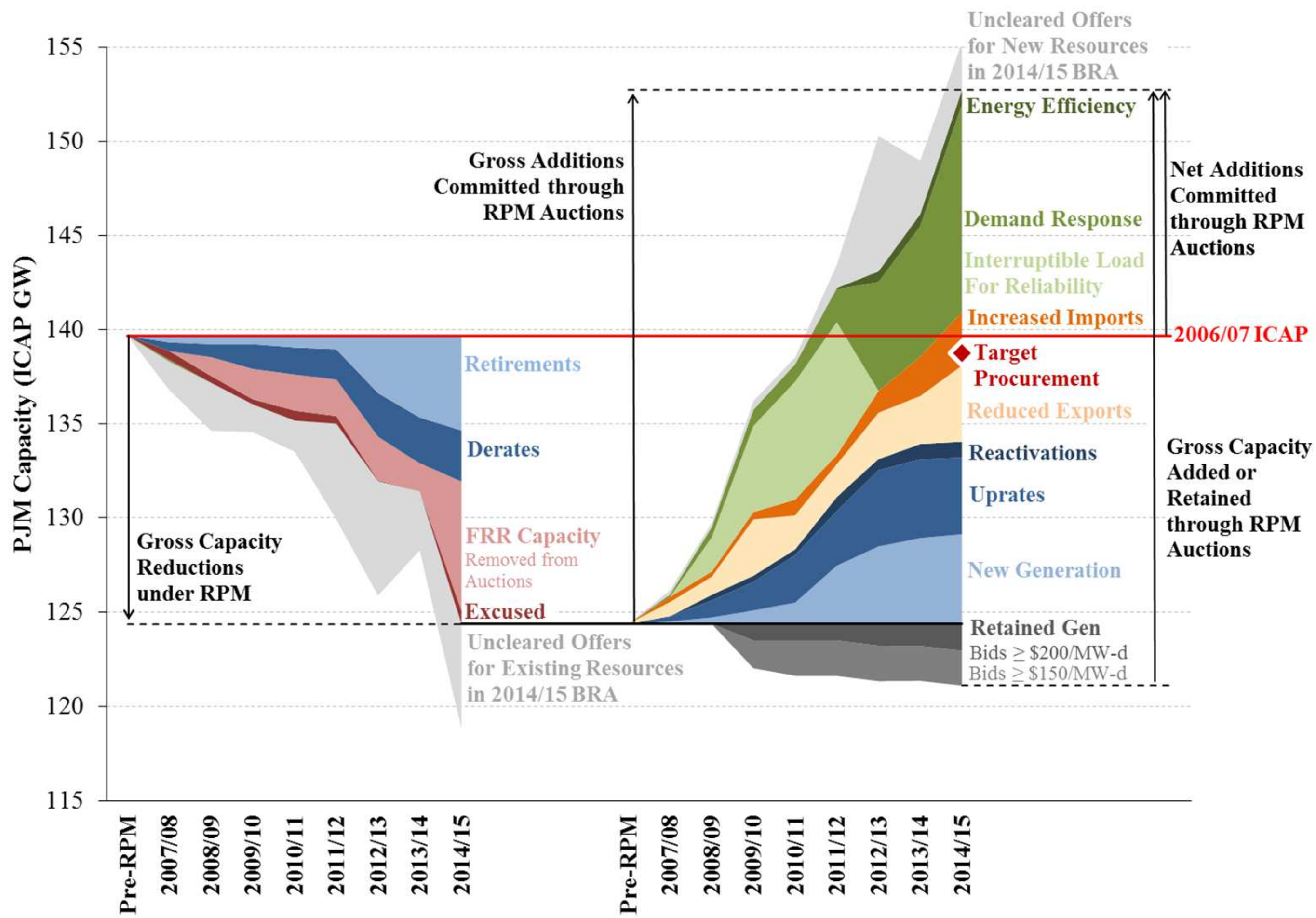
    - Other CAISO proposed flexibility metrics do not reflect start times
      - Load following metric only reflects start times for resources that can start within an hour

- Do IOU valuation methodologies capture the value of faster starts?
  - Realistic future hourly price shapes?
  - Realistic modeling of unit commitment and dispatch?

- AS/FlexiRamp

- To the extent that start-up and no-load costs may be socialized, does anyone have the incentive to minimize them?

“Portfolio approach”/Should procurement be segmented?



Conclusion

- Flexibility requirements need to be defined
- The relationship between the specific physical characteristics of resources and flexibility requirements merits careful consideration
- Allow competition between different classes of resources, including DR, storage, new and existing capacity, and uprates through:
  - All-source RFOs
  - A forward capacity market

CALPINE®

NYSE CPN

Workshop 2:50 – 3:25

- EnerNoc

LTPP, Storage and Demand Response Workshop

Mona Tierney-Lloyd, Director, Regulatory Affairs

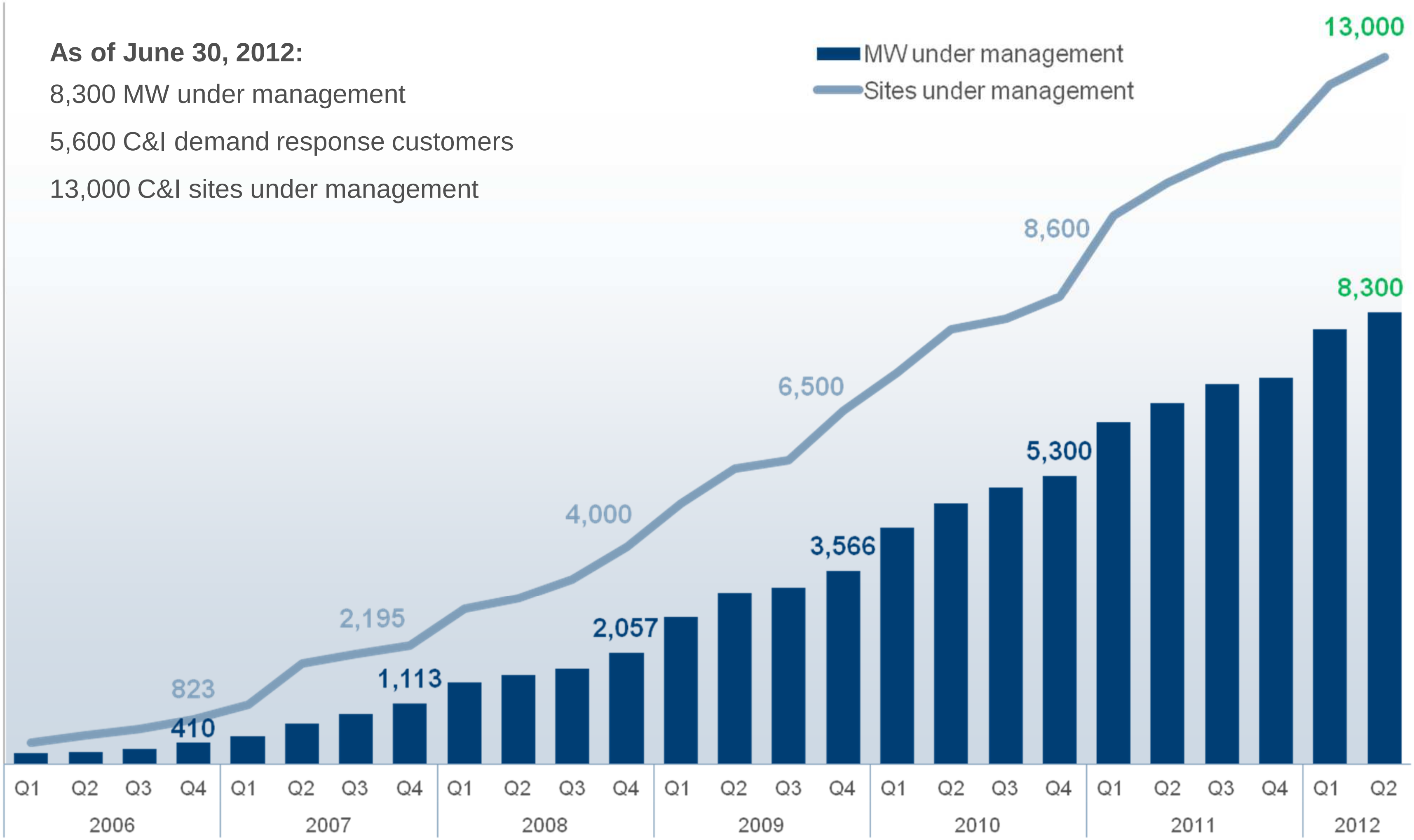
September 7, 20122

About EnerNOC

- **Proven Customer Track Record**
  - 5,600 customers across 13,000 sites with 8,300 MW's of demand response capacity in North America, Europe, Australia, and New Zealand
  - 99% customer retention rate
  - Highest industry customer satisfaction rating
  - Over $500 million in customer payments/savings to date
  - Simple, risk-free commercial agreements
- **Full Value and Technology Offering**
  - Energy management application platform addresses demand and supply-side
  - Combine technology, managed services, and market access
  - More than $100 million invested to date in technology
  - 24/7/365 Network Operations Center, real-time metering and web-based monitoring
- **World-Class Team and Resources**
  - 600 employees and growing fast – multiple "top places to work" awards
  - Publicly traded on the U.S. NASDAQ (ENOC)
  - Over $79 million in cash on balance sheet

ENERNOC

A History of Rapid Growth



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Agenda

- **LTPP, DR and Renewable Integration**
- **Flexible Capacity and Technology**
- **Product Definitions**
- **Challenges**
- **RFOs**

Discussion and Questions

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Scenario Synopsis

Increased Penetration of renewable distributed resources

Forecast retirement of existing gas-fired generation in LCAs due to OTC

Changes in the planning and operational needs of the system from a Peak Day (MW) to Operational Flexibility (MW/min) basis

To date, the only resources considered to meet this capability have been gas-fired generators

DR can provide a portion of the renewable integration need—development and removal of barriers

ENERNOC

Studies on Operational Impacts of Renewable Integration

GE Energy Study for NREL "Western Wind and Solar Integration Study" (May 2010)

Regulatory Assistance Project Study for the Western Governor's Association (June 2012)

Flexible capacity is one of several operational changes that need to be adopted to efficiently integrate renewable resources

- Expanded balancing area cooperation, including dynamic transfers
- Expand sub-hour dispatch and Intra-hour scheduling
- Improved forecasting of wind and solar
- Commit additional operating reserves
- Build or increase utilization of transmission
- **Target new or existing DR to assist with variability**

"It is more cost-effective to have demand response address the 89 hours of contingency reserve shortfalls rather than increase spin for 8760 hours of the year. Demand response can save up to $600M/ yr ($510M/yr in 2009$) in operating costs versus committing additional spinning reserves." NREL WWSIS at p. 22

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Long-Term Procurement Process

Local Capacity Requirements-Phase 1

- 10-Year Planning Horizon, expanded to 20-year horizon
- High load scenario (assume discounted DR materializes)
- Assume retirements of OTC plants
- Assume DG goals are met
- Assume 2400-3700 MW of LCR need in Southern California
- Assume only gas-fired generation will meet the need
- **Assume ZERO LCR capability is met by DR resources**
- Assume ZERO uncommitted EE

System Capacity Needs-Phase 2

- Scenarios are still being determined
- Under most scenarios, no system need for next 10 years
- **Assume no growth in DR as mid-range scenario (~5,000 MW)**
- Assume a +/- 10% of mid-range for high and low scenarios

On its face, the DR assumptions are inconsistent with EAP

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These Assumptions Are Pessimistic

DR Resources Can be Dispatched on a LCA Basis

- D.11-10-003 requires local dispatch for local RA credit
- Some DR is already locally dispatchable and more will be available in the near-term

Directionally, technological capability and need is moving DR toward being a faster response resource

Technology, Smart Grid and Markets Will Expand DR Services

- Utility smart grid deployment plans expect additional DR and EE potential as a result of enabling technologies.
- OpenADR protocols and utility incentives will expand automated load response
- Data access protocols (OpenADE/ESPI, Zigbee, SEP 1.x or 2.0), HAN deployments
- Expanded access to markets, need for renewable integration

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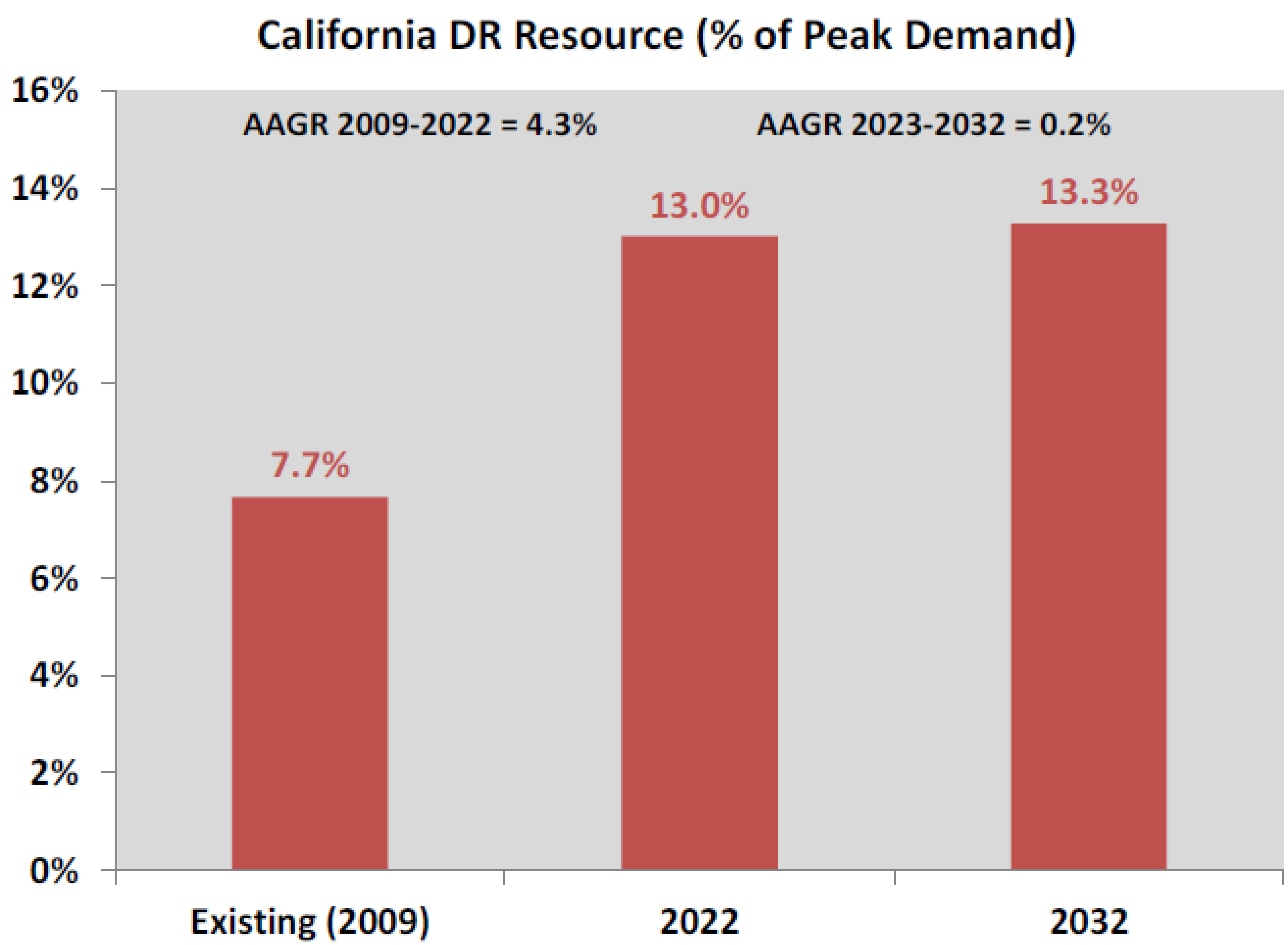
California



25

The Brattle Group

Policy and regulatory drivers contribute to the variation in DR impacts

- Possibly the single most influential driver of DR market penetration is the extent to which state regulators support its development
- For example, California's Energy Action Plan prioritizes demand-side resources in the state's energy mix, and the California IOUs have built significant DR portfolios as a result
- Even a general policy focus on demand-side participation, such as Arizona's DSM energy reduction goal of 22% by 2020, has been shown to correlate with greater impacts from DR programs (Smith and Hledik, 2012)
- Support for innovative pricing schemes can also act as an indicator of future DR and dynamic pricing efforts; the Colorado PUC requires that the state's utilities offer an inclining block rate to residential customers
- States without policy support for demand-side initiatives, such as Montana and Wyoming, have demonstrated little DR market penetration

Various Forms of Demand Response

Supply-side, demand-side, and fast-response resources

Supply-Side Resources

- Capacity, economic or emergency energy, ancillary services
  - Still working on the rules for wholesale market participation in CA
  - Economic and logistical barriers

Demand-Side Resources

- Dynamic Pricing (CPP and PDP)
- DLC

Fast-Response Resources

- Under-frequency response
- Spinning and non-spinning reserves
- Regulation

All of these can provide benefits to the system by reducing demand and could displace some supply resources

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Summary of Navigant Survey of How DR Is Used by Other ISOs/RTOs, and by Two Utilities Where There Are No Organized Wholesale Markets

	Use of DR for Ancillary Services			Use of DR to Avoid Capacity	Use of DR to Avoid Energy
	Spinning Reserves	Non-Spinning Reserves	Regulation		
ERCOT	Yes (50% cap)*	Yes	Yes	Not Applicable	Yes
NYISO	Yes	Yes	Yes	Yes	Yes
PJM	Yes (25% cap)*	Yes	Yes	Yes	Yes
ISO-NE	No	No	No	Yes	Yes
MISO	Yes (10% cap)*	Yes	Yes	Yes**	Yes
BPA***	No	No	Pilot Program (Load Following)	Yes	Not Applicable
HECO***	No	Pilot Program	No	Yes	Not Applicable

KEY:
Yes/Pilot Program = DR is able to participate, although participation may still be limited (e.g., virtually no DR participates in ERCOT's non-spinning and regulation markets).

No = Market/service exists in that jurisdiction, but DR is not able to participate.

Not Applicable = Market/service does not exist in that jurisdiction.

* Maximum percentage of ISO/RTO's spinning reserve requirements that DR is allowed to provide

** Bonneville Power Administration (BPA) has a voluntary market

*** Hawaiian Electric Company (HECO) has no organized markets

Based on information available as of April 2012.

NAVIGANT ENERGY

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Flexible capacity must support ISO operational needs and align with existing market structures.

Three Categories of Flexible Capacity:

► Maximum continuous ramping

- *The megawatt amount and duration by which the net load (load minus wind and solar) is expected to change continuously in a given direction within a month DR can blunt the ramp need.*

► Load Following (≤ 60 minutes)

- *The maximum megawatts the net load is expected to change in a given hour of a given month DR can decrease net load*

► Regulation (≤ 5 minutes)

- *The maximum megawatts the net load is expected to change between intra 5-minute dispatch intervals   More challenging*

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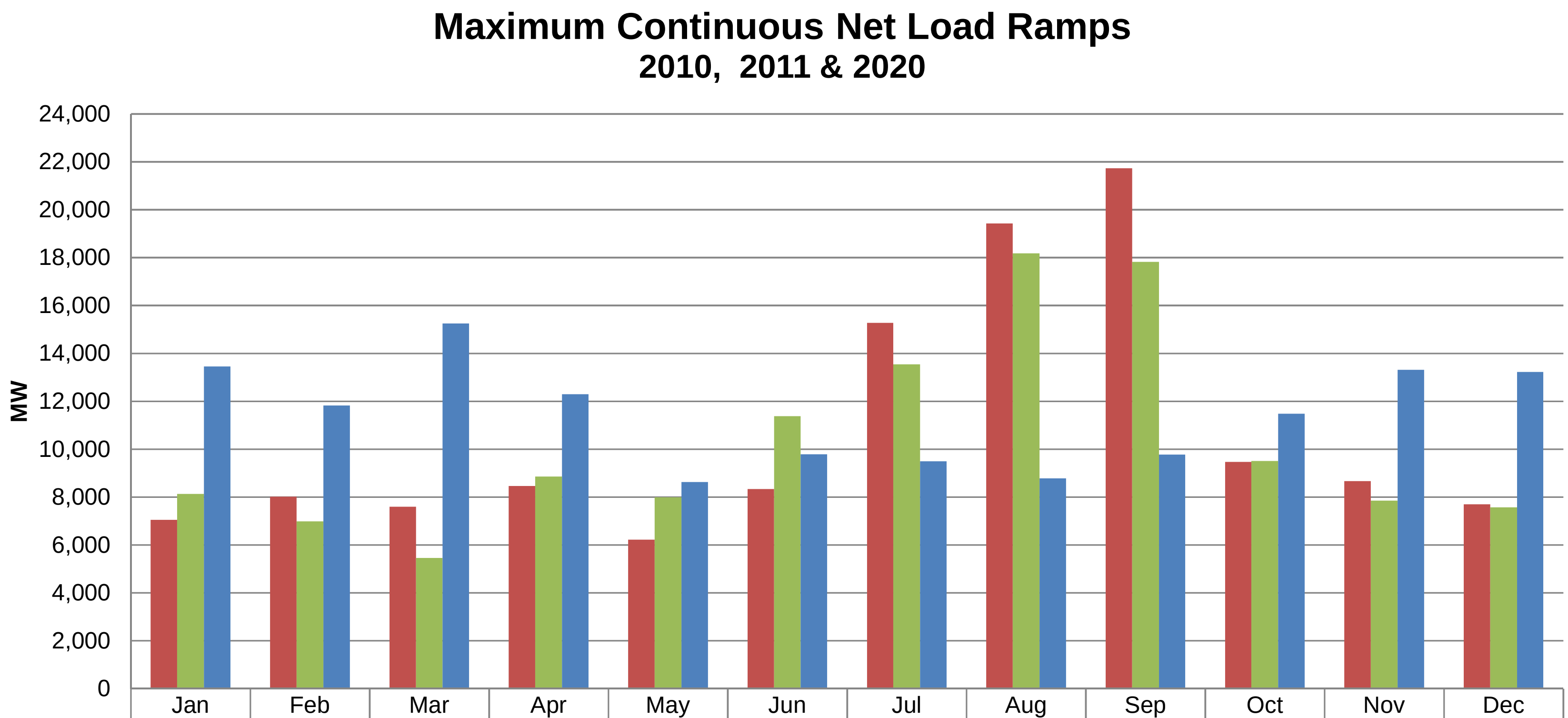
Maximum continuous net load ramps (trough to peak) -Actual 2010 & 2011--- Simulated 2020

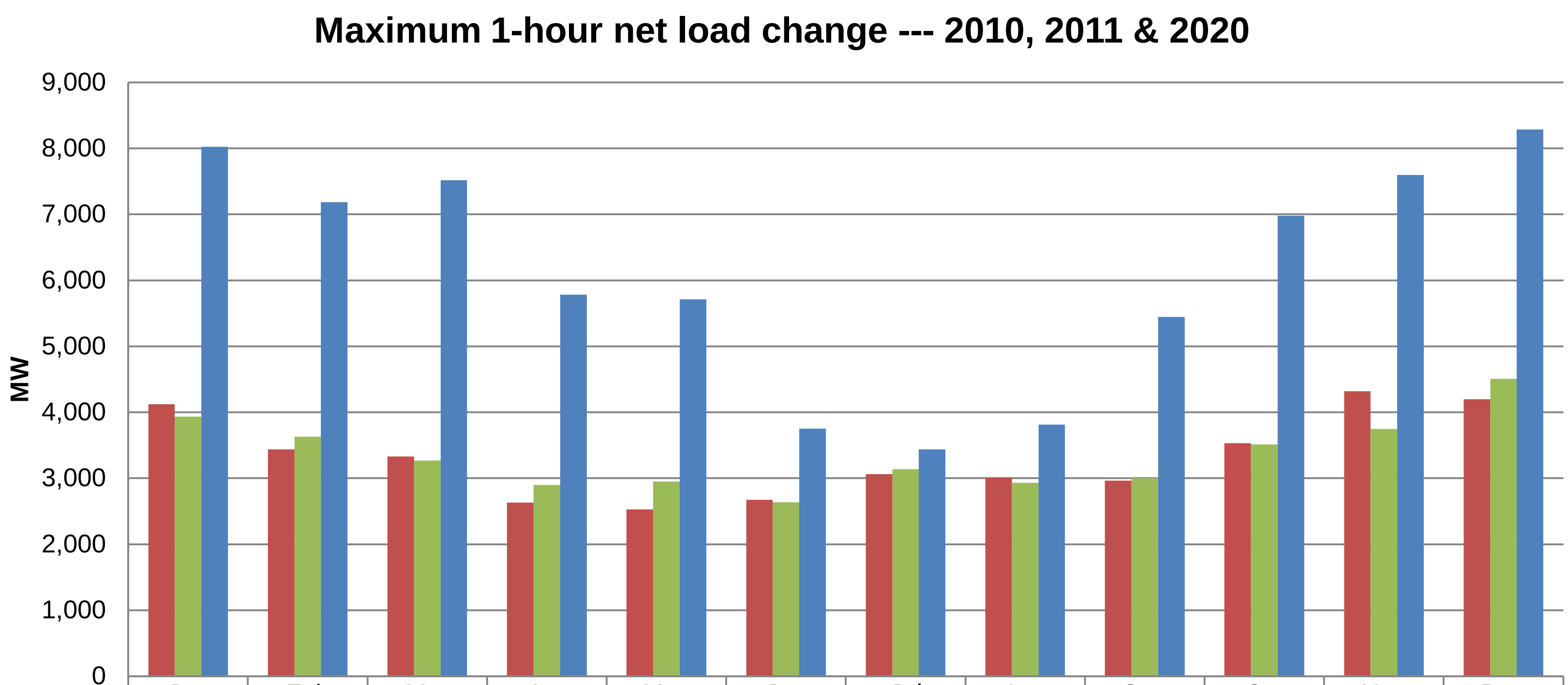
Observation: Range of continuous ramp decreases in summer periods.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	7,057	8,022	7,594	8,465	6,217	8,337	15,275	19,432	21,732	9,464	8,667	7,706
2011	8,133	6,982	5,453	8,859	8,000	11,382	13,544	18,181	17,824	9,510	7,855	7,577
2020	13,459	11,825	15,254	12,298	8,630	9,782	9,496	8,785	9,777	11,483	13,308	13,234

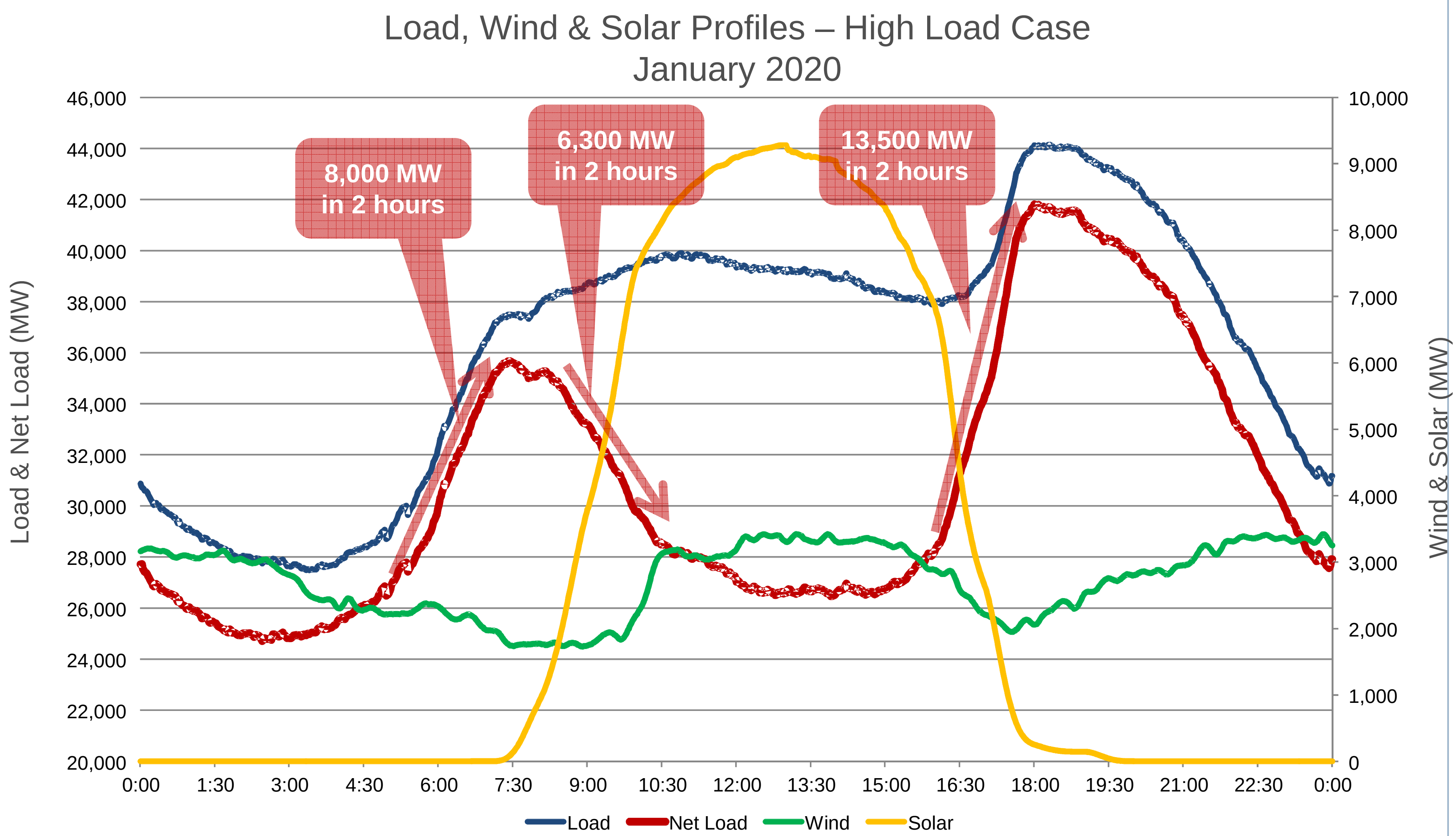
Maximum 1-hour net-load change comparison --- Actual 2010 & 2011 --- Simulated 2020

Observation: Hourly changes increases in 2020 in shoulder periods.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	4,120	3,440	3,329	2,629	2,527	2,675	3,061	3,010	2,963	3,531	4,321	4,198
2011	3,935	3,630	3,271	2,897	2,951	2,637	3,137	2,933	3,004	3,514	3,746	4,506
2020	8,022	7,186	7,516	5,783	5,714	3,753	3,439	3,811	5,443	6,979	7,597	8,286

Conventional resources will be dispatched to the net load demand curve – High Load Case



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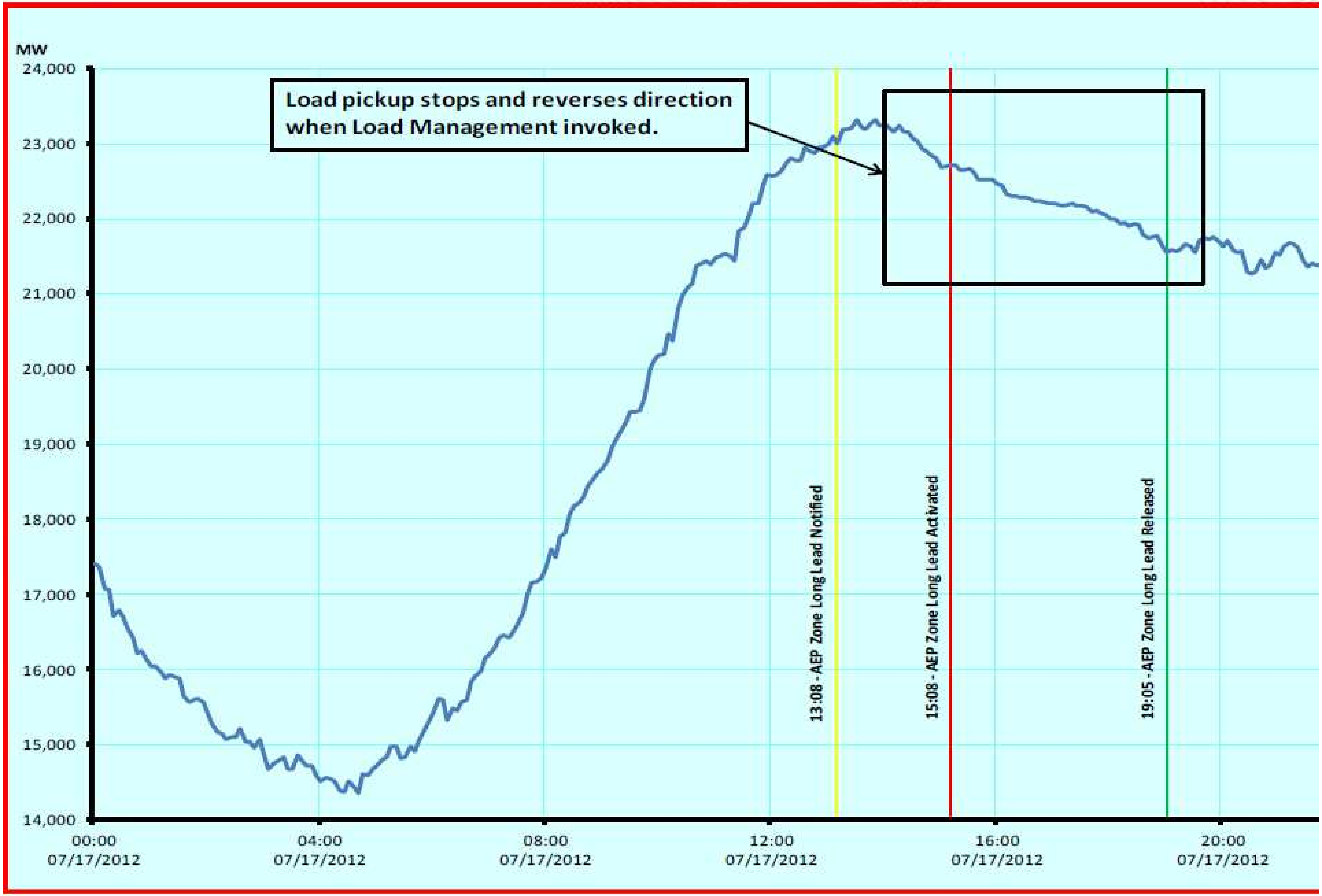
Instantaneous AEP Zonal Load 7/1



Challenges

Current Flexible Capacity Definitions are Designed for Generators

- Pmin and Pmax do not translate to load
- Not clear how DR would qualify for these services

Either define how DR fits under these definitions or create DR definitions

Product Definitions are not fully developed--Unknowns:

- Availability requirements
- Frequency or duration of dispatches
- Price/Value

Technological and Regulatory Barriers to Participation

- Telemetry
- WECC Limitations
- Cost-Effectiveness
- Developmental Stage

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Customer Perspective

Get the Incentives Right

- Customer payments should value the type of resource provided and included the value in cost effectiveness calculations
  - Fast response
  - Location-specific
  - Annual availability
  - Dispatch frequency/forecasting
- Customer automation incentives through utilities, include 3rd parties
- Education and acceptance

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Multi-Purpose Demand Response

In order to meet resource needs, DR portfolios will be asked to provide a variety of resources.

Emergency DR Resource (100 MW)

- *Typical dispatch: 6 hours duration; 1-2x/year; 60-minute notice*
- *Load reduction only*

Peak-shaving DR Resource (50 MW)

- *Typical dispatch: 4 hours duration; 10-15x/year; 30-minute notice*
- *Load reduction only*

Spinning and Non-Spinning Reserves DR (25 MW)

- *Typical dispatch: 30-minute to 2 hours duration; 10-50x per year; 10-minute notice*
- *Load reduction only*

Load-following DR Resource (15 MW)

- *Typical dispatch: 1-2x/day; 30-minute duration; 5-minute notice*
- *Load reduction or increase*

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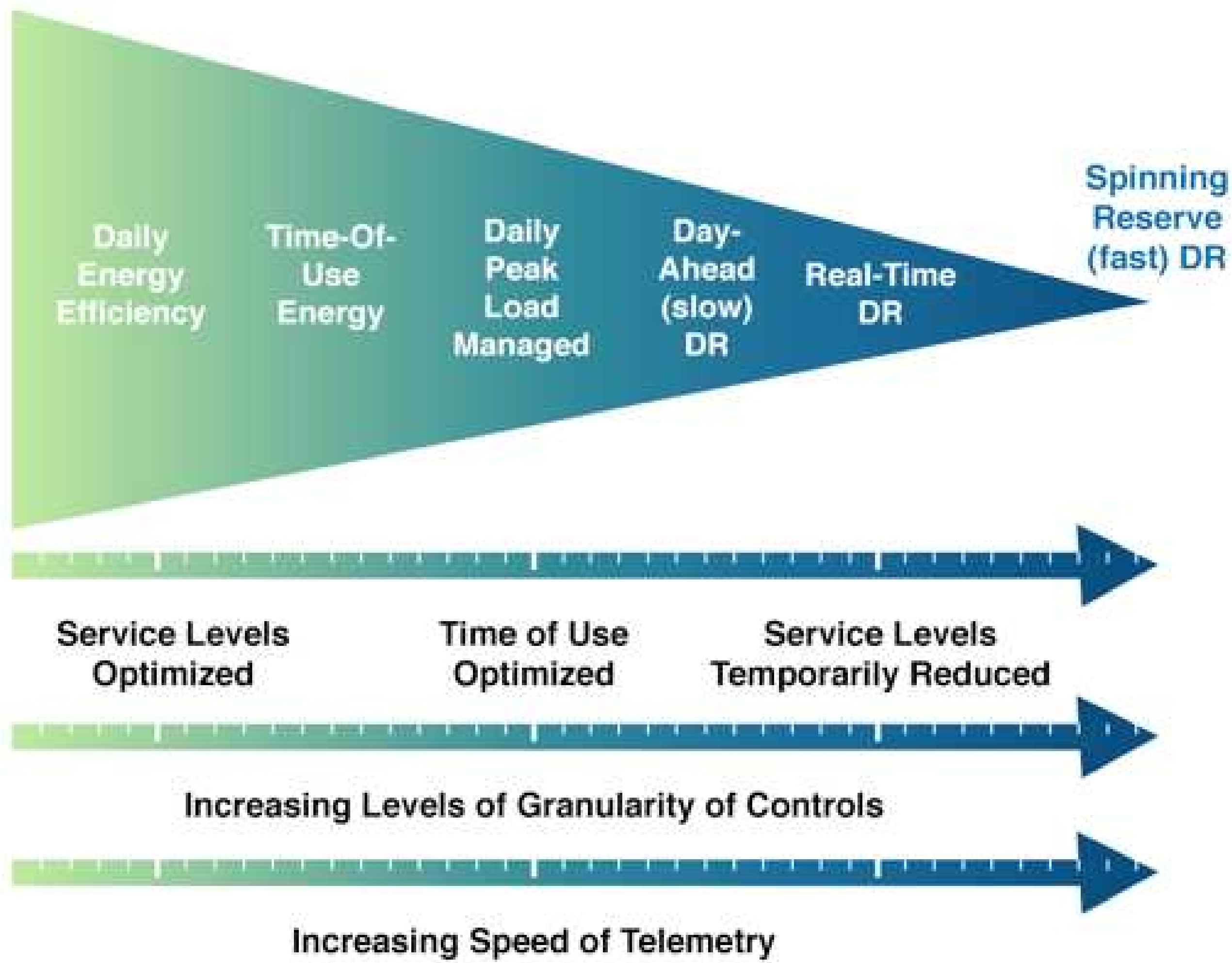
Accommodating varying levels of sophistication

Varying levels of technical rigor and customer sophistication are required for the various types of demand response, but ALL services provided by generation can also be provided by demand response



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[EnerNOC **Experience** with Quick Response DR

Some resources provide **ancillary services** or qualify as **spinning/non-spin reserves**

Approximately 1,900 sites in our portfolio feature automated remote dispatch

<table>
<tr><th></th><th>Program</th><th>Notification</th><th>Max Event Length</th><th>EnerNOC Portfolio</th></tr>
<tr><td rowspan="4">Restructured Market</td><td>ERCOT Emergency Interruptible Load Service (EILS)</td><td>10 min</td><td>Up to 8 hours</td><td rowspan="7">750+ Sites
380+ MW</td></tr>
<tr><td>ERCOT Load acting as a Resource (LaaR) - Responsive and Non-Spinning Reserves</td><td>Instantaneous to 10 min</td><td>No maximum</td></tr>
<tr><td>National Grid (UK) Short-Term Operating Reserves Market (STOR)</td><td>20 min</td><td>Up to 4 hours
Average 45 minutes</td></tr>
<tr><td>PJM Synchronized Reserves Market (SRM)</td><td>10 min</td><td>Max 30 min. / Avg. ~23 min.</td></tr>
<tr><td rowspan="3">Utility Bilateral</td><td>San Diego Gas & Electric Clean Gen</td><td>10 min</td><td>Up to 8 hours</td></tr>
<tr><td>PNM Peak Saver</td><td>10 min</td><td>Up to 6 hours</td></tr>
<tr><td>Salt River Project Power Partner</td><td>10 min</td><td>Up to 6 hours</td></tr>
</table>

RFO Considerations

Maintain loading order priority and designate a % RFO set aside

All –source RFOs will try to fit the DR square peg into the generation round hole

- **Operating characteristics are different**
- **DR is not a base-load resource**

Make clear what products are being sought up-front and how DR can participate

- **Current definitions do not contemplate DR**

Stagger solicitations so that DR advances over time can be included

- **Capabilities are going to increase over time; don't lock out future potential**

Establish a value for fast-response resources, with locational characteristics that encourages participation and is higher than system, slow-response resources

- **This is a fundamental shift away from peak requirements resourcing**

ENERNOC

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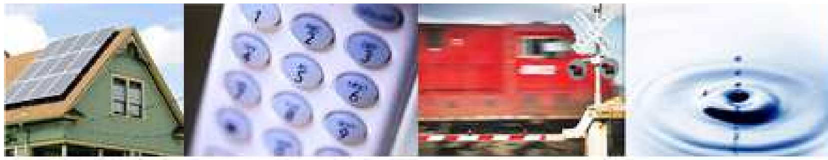
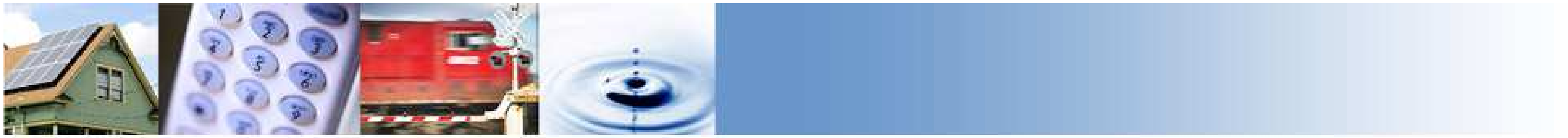
mtierney-lloyd@enernoc.com



Workshop 3:25 – 3:45

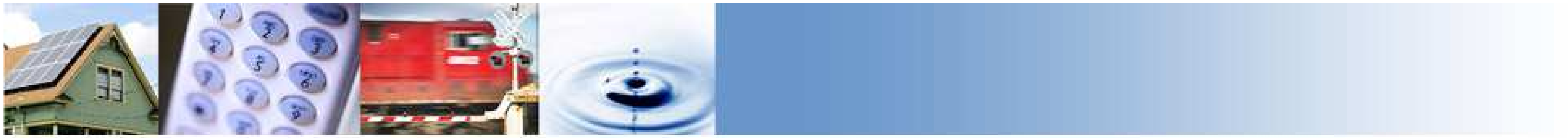
- TURN – No Slides

Wrap Up / Next Steps



LTPP/ES Next Steps

- Staff anticipates an ALJ ruling requesting comments to be issued the week of September 10th.
- A comment template will be provided to guide responses.
- Phase 2 of the Storage proceeding will also look to those comments for Use Case analysis of storage benefits.



LTPP Schedule

- Track I (Local Area Reliability)
  - 9/24: Briefs
  - 10/12: Reply Briefs
  - Nov/Dec: Proposed Decision
- Track II (System Reliability)
  - 9/7: Technical comments
  - 10/1: Policy comments
  - November: Proposed Decision
- Track III (Bundled Procurement / Rules)
  - Q3 2012 start expected

Energy Storage Schedule

- Phase 2 -- PHC Sept. 4, 2012
- Scoping Memo
- Workshop on Cost/Benefit, Sept. 24
- Workshop on Use Case Development, October 15-16
- Legislative deadline: October 1, 2013.

Thank you!
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